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RANGER OIL LIMITED



1997 ANNUAL REPORT

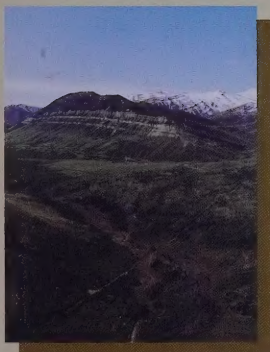
Corporate Profile

Ranger Oil Limited is a publicly traded Canadian energy company with over 40 years experience in international exploration, development and production of crude oil and natural gas. The recent merger with ELAN Energy Inc. has added heavy oil to the Company's asset base.

Ranger's initial growth was based on exploration and production in Canada's Western Sedimentary Basin, an area that remains a key component of the Company's operations. In 1957 the Company started pursuing international opportunities, in particular, offshore prospects in the United Kingdom sector of the North Sea.

Today, Ranger Oil has operations in Canada, the US Gulf of Mexico, the North Sea, Angola, Peru, Ecuador, Namibia and Côte d'Ivoire.

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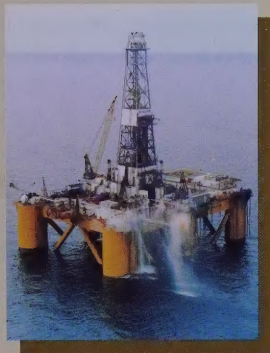
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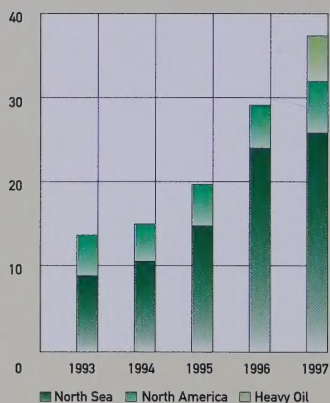
NOTICE OF ANNUAL MEETING

The Annual Meeting of Shareholders will be held at 10:00 a.m.
on Thursday, May 7, 1998 at the Metropolitan Centre,
333 - 4th Avenue S.W., Calgary, Alberta, Canada.

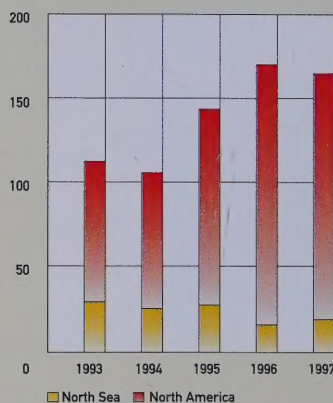


Financial Operations Highlights

DAILY OIL & NGL PRODUCTION
(before royalties) (thousand barrels)



DAILY GAS PRODUCTION
(before royalties) (million cubic feet)



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FINANCIAL (millions of US dollars, except per share amounts)

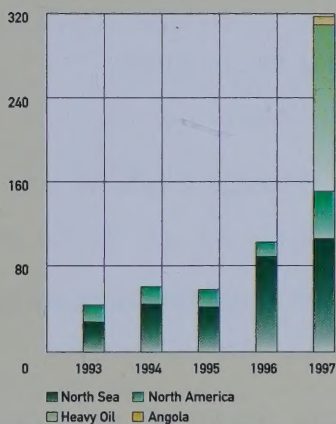
	1997	1996
Revenues	\$ 351.0	\$ 299.0
Earnings (loss)	\$ 9.1	\$ (55.8)
Per common share	\$ 0.09	\$ (0.57)
Funds generated from operations	\$ 145.9	\$ 144.1
Per common share	\$ 1.38	\$ 1.46
Capital expenditures, net	\$ 644.8	\$ 179.4
Working capital (deficiency)	\$ 4.0	\$ (68.6)
Long-term debt	\$ 427.0	\$ 100.0
Total assets	\$ 1,369.2	\$ 837.3
Common shareholders' equity	\$ 645.4	\$ 409.4
Common shares outstanding (millions)	125.9	99.0

OPERATIONS

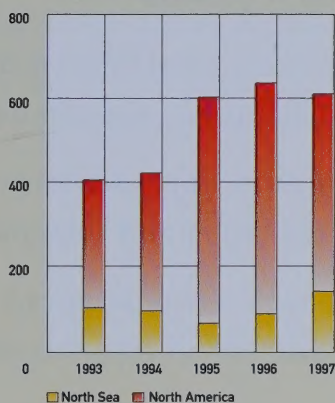
Daily production, before royalties

Crude oil and natural gas liquids (thousand barrels)		
North Sea	26.9	24.1
North America – conventional	6.1	5.1
– heavy oil	5.4	–
	38.4	29.2
Natural gas (million cubic feet)		
North Sea	19.5	16.3
North America	145.6	154.0
	165.1	170.3

PROVEN & PROBABLE OIL & NGL RESERVES
(before royalties) (million barrels)



PROVEN & PROBABLE GAS RESERVES
(before royalties) (billion cubic feet)



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EXPLORATION ACREAGE (thousand net acres)

	1997	1996
North Sea	349	300
North America – conventional	1,530	1,257
– heavy oil	108	–
International	3,210	2,467
	5,197	4,024

RESERVES, BEFORE ROYALTIES*

Crude Oil and Natural Gas Liquids (million barrels)

Proven

North Sea	107.2	90.3
North America – conventional	36.0	10.3
– heavy oil	65.3	–
International	8.5	–
	217.0	100.6

Probable

North America – conventional	9.3	3.4
– heavy oil	92.6	–
	318.9	104.0

Natural Gas (billion cubic feet)

Proven

North Sea	144.6	91.4
North America	334.5	381.5
	479.1	472.9

Probable

North America	148.0	164.9
	627.1	637.8

* These amounts include fields in production or approved for development. They do not include an additional 50 million barrels of oil equivalent of reserves attributable to potential field developments and extensions in the North Sea and Côte d'Ivoire.

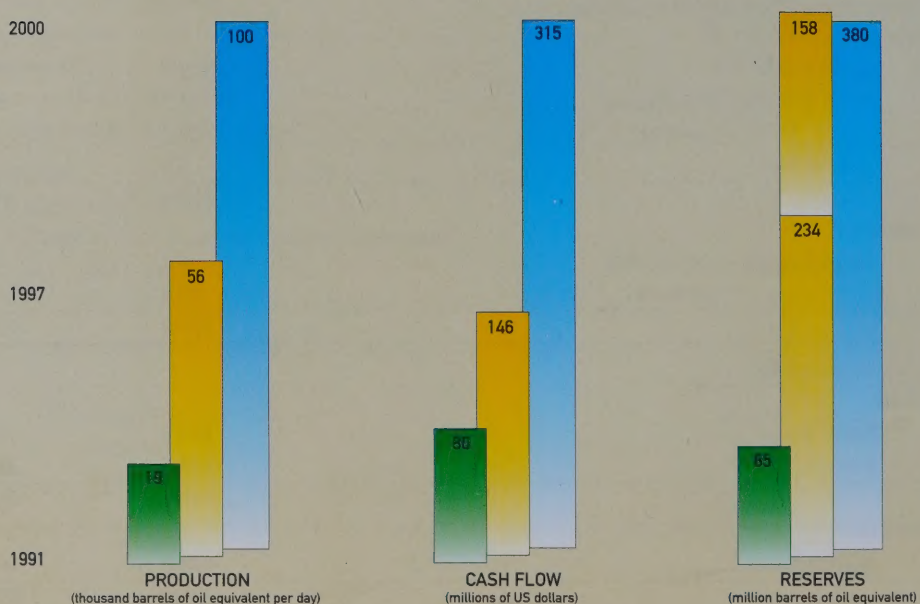
Strategic Plan

Ranger's strategic plan is based on building a foundation for long-term growth:

- Maintain a balanced program of global exploration, development, exploitation and acquisitions;
- Increase North American production through exploration, exploitation and selective acquisitions;
- Manage newly acquired heavy oil asset base for substantial growth when oil price improves;
- Increase North Sea production through continued development of existing discoveries and selective exploration;
- Expand activity in International areas;
- Maintain a prudent financial position.

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Targets



President's Message

Strategy for Adding Value

The previous page outlines our strategy for adding value which forms the basis of our five year business plan. The underlying objective is to double shareholder value every five years.

In our strategy we have now incorporated the recently acquired Heavy Oil Division and adjusted our year 2000 targets upwards to reflect the additional outstanding shares as a result of the purchase of ELAN Energy Inc. (ELAN).

1997 WAS A YEAR OF BUILDING FOUNDATIONS

The following are the major highlights for 1997:

- Total proven and probable reserves increased 125 percent, from 174 to 392 million barrels of oil equivalent;
- Additions to proven and probable conventional oil and gas reserves from extensions, discoveries and revisions replaced 250 percent of 1997 production;
- Oil production increased 32 percent;
- ELAN acquired September 29, 1997;
- Shares in issue increased by 27 percent broadening the shareholder base;
- Substantial additional acreage acquired in West Africa and West of Shetlands;
- Two potentially high impact wells in the Northwest Territories currently testing.

The major highlight was the acquisition of ELAN in September 1997. At the time, our decision was predicated on acquiring a substantial resource base (over 5 billion barrels in place) that would position the Company for growth beyond the year 2000. Notwithstanding the low oil price environment that exists today, our rationale has not changed. Future growth in the Canadian Western Sedimentary Basin will be primarily from natural gas and heavy oil. Ranger is well positioned to participate in both commodities.

The recent steep decline in oil prices and widening heavy oil differential has had a major impact on the heavy oil operations. In response, we have implemented numerous cost saving initiatives, minimized our ongoing capital program and shut-in approximately 2,000 barrels per day of uneconomic production. Our strategy is to remain focused on asset management and, once prices rebound, aggressively exploit our heavy oil reserve base. With conventional oil reserves continuing to decline in Western Canada, refineries converting to accommodate a heavier slate of crudes and new technologies expected to improve the economics of heavy oil, Ranger will have a substantial long-term base of North American oil production.

In addition to the heavy oil reserves, ELAN provided Ranger with 36 million barrels of equivalent conventional reserves, with fourth quarter daily production averaging 8,855 barrels of oil and 9 million cubic feet of gas.

In Canada, well P-66 in the Fort Liard area of the Northwest Territories reached total depth in January 1998. Initial test results have indicated a commercial discovery. Further testing is underway and additional appraisal and evaluation work will be required to determine the size and significance of this discovery.

In the Fort Norman area, early spring break-up conditions have resulted in the Little Bear well being cased and suspended after providing encouraging results. Further evaluation and testing will be done on this prospect in the 1998/99 winter drilling season. A second well in this area at Nota Creek has been suspended.

In the United Kingdom, the commencement of full-scale production from the Banff and Pierce fields will substantially boost oil production in the fourth quarter of 1998. These developments together with the Columba 'E' and Kyle fields in the North Sea and Kiame in Angola should allow Ranger to achieve production of around 100,000 barrels of oil equivalent in 1999, or almost twice the level of production for 1997.

A major portion of our activities in 1997 focused on building our exploration portfolio to position the Company for growth beyond 2000. Ranger acquired two prospective new blocks in the UK West of Shetlands area offsetting a previous oil discovery.

In Côte d'Ivoire we have built a large position including the previously developed Espoir field. In Angola, the deep-water Tertiary play is probably the most exciting exploration play in the world today. In addition to our current interest in Block 4 offshore Angola, Ranger has acquired a 25 per cent interest in deep-water Block 19, subject to agreeing final terms with the state oil company and government. This new acreage should see substantial exploration activity over the next two years.

Outlook for 1998

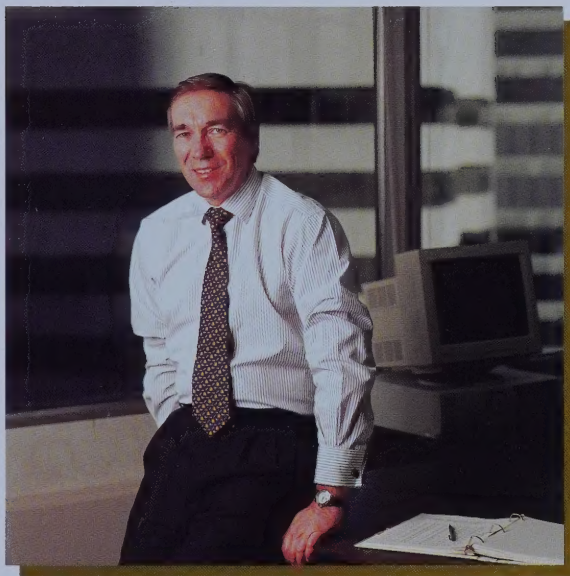
The year 1997 ended with oil prices over \$7.00 per barrel lower than 12 months earlier. The combination of increased OPEC quotas in late 1997, the Asian financial crisis, and a relatively warm winter in the northern hemisphere, has led to higher production volumes against slowing demand growth. Prices have continued to deteriorate through the first quarter 1998.

Notwithstanding this lower oil price environment, Ranger is continuing this year with our major development program, primarily in the North Sea, which will lead to a substantial increase in production during the fourth quarter of 1998. We have revised our 1998 capital budget downward by \$50 million to reflect the outlook for lower prices and cash flow.

The combination of low oil prices and high service sector costs, particularly in the offshore drilling rig market, will result in a slowdown in our offshore exploration drilling activities in 1998. Our offshore exploration focus will be to build our prospect inventory and, with a large seismic program, position the Company for a major drilling program in 1999. In Canada our focus will be on drilling our natural gas prospects where new transportation export capacity augurs well for Canadian natural gas prices.

Ranger's achievements in 1997 and its plans for 1998 continue to position and move us forward to achieving our goals and building a solid platform for continued and sustainable growth.

I would like to thank our Board of Directors for their support and our dedicated employees for their success in achieving these results.



F.J. Dymont
President and Chief Executive Officer
March 13, 1998

REVIEW OF OPERATIONS



The Liard Valley in the Northwest Territories. Ranger's P-66 gas discovery is currently testing.

North America

Strategic Plan

- Build short to medium term growth in production and cash flow through active exploration, exploitation and acquisition programs. These activities are focused in Western Canada and offshore US Gulf of Mexico.
- Selectively pursue high impact exploration primarily in the Northwest Territories of Western Canada.
- Concentrate on asset management in core areas including cost control, property optimization, exploitation and new technological applications. In non-core areas, rationalize portfolio through property dispositions or swaps.
- Manage Ranger's newly acquired heavy oil asset base in readiness for improved oil prices.

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Production & Reserves

		Average Daily Production		
	Proven Reserves	1997	1996	1995
	(million barrels)		(barrels)	
Crude Oil & Natural Gas Liquids				
Canada – conventional	35.6	5,593	4,435	4,680
– heavy oil	65.3	5,400	–	–
USA	0.4	547	716	268
	101.3	11,540	5,151	4,948

		Average Daily Production		
Proven Reserves		1997	1996	1995
(billion cubic feet)		(million cubic feet)		
Natural Gas				
Canada	322.8	131.4	140.8	105.3
USA	11.7	14.2	13.2	10.5
	334.5	145.6	154.0	115.8

Conventional Oil and Gas

CANADA

Northeastern British Columbia

Northeastern British Columbia is Ranger's largest gas producing area and possesses substantial upside for growing production and reserves. Ranger has a significant presence in the area including a large land position. The area is characterized by long-life gas reservoirs.

HELMET/MIDWINTER

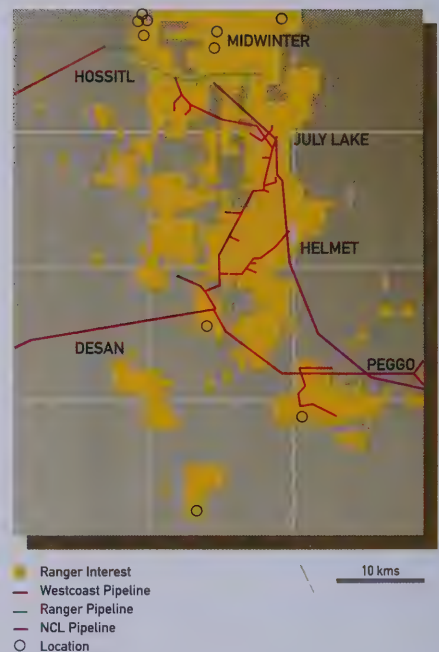
Ranger-operated Helmet is the Company's largest gas producing property. Production increased in 1997 through the acquisition of approximately 17 million cubic feet per day from Gulf Canada Resources Ltd. in December 1996. The 1996/1997 drilling program included three horizontal and six vertical exploration and appraisal wells which added nine million cubic feet per day.

Helmet has direct access to the NOVA pipeline to Alberta which increases transportation and marketing options from this core area.

In December 1997 Ranger entered into an alliance with Chesapeake Energy Corporation which purchased a 40 percent interest in all properties in the Helmet area excluding the July Lake pool. All future operations will be conducted on a 60/40 basis between Ranger and Chesapeake. Production and proven and probable reserves sold amounted to 16 million cubic feet per day and 70 billion cubic feet respectively. The purchase consideration was \$50 million.

The Helmet/Midwinter area continues to be a prime focus for production and reserve additions. The 1997/98 winter drilling program will include six horizontal wells, four exploratory wells, two joint interest wells and installation of additional field compressors.

HELMET/MIDWINTER



Northern Alberta

Ranger added significant conventional oil production and reserves in northern and northwestern Alberta principally through six properties acquired with ELAN in September 1997.

At Edson, Ranger plans to participate in drilling three exploratory wells targeting new gas pools. The first well in the project discovered a new Viking pool and the other two wells will be drilled in the first quarter of 1998.

East Central Alberta

East central Alberta is characterized by shallow gas reserves, low geologic risk and high potential for low cost reserve additions. The primary development focus in 1997 was at Elk Point where construction of a gas plant and pipeline added 10 million cubic feet per day of production in the third quarter.



Claresholm Gas Plant in Southern Alberta

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Southern Alberta

Southern Alberta continues to be an active development area. Rationalization of ownership at Claresholm/Parkland will facilitate further exploitation and exploration. Ranger's two core oil properties, Long Coulee and one acquired with ELAN, Turin, continue to be optimized and further exploitation opportunities have been identified. During 1997 one exploratory well and four appraisal wells were drilled in Long Coulee resulting in two oil wells and one gas discovery.

Southeastern Saskatchewan

Southeastern Saskatchewan is one of Ranger's major oil producing areas. The ELAN acquisition added conventional oil production from two properties in southeastern Saskatchewan along with good exploratory potential. At Kisbey, Ranger added production of 190 barrels of oil per day through a 50 percent interest in 18 producing wells, and another 539 barrels of daily production was added at Weyburn.

The Company is increasing its exploratory activity in 1998 and plans to participate in drilling three wells by the end of the winter drilling season.

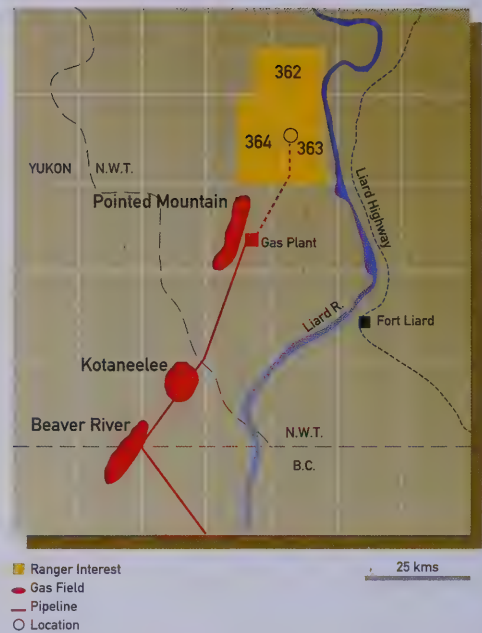
Northwest Territories

Ranger's exploration in the Northwest Territories is targeting large prospects for both oil and gas. Exploration is underway in two areas, Fort Liard and Fort Norman.

Ranger has 50 percent interests in two licences at Fort Liard located close to the borders of British Columbia and the Yukon, and which are within 24 kilometres of a major gas pipeline and infrastructure. Exploration well P-66 was spudded in January 1997 to target a gas prospect with potential reserves up to 600 billion cubic feet. The geological structure was identified on 2-D seismic and, while plans called for the target depth to be reached in six months, the well had to be sidetracked twice before completion in February 1998. Evaluation of the initial well results indicates a commercial gas discovery and further testing is being conducted to determine the size of the pool. Installation of a pipeline and tie-in to nearby facilities is anticipated in the winter of 1998/99. Additional well locations are available depending upon the size of the pool.

In the Fort Norman area, Ranger acquired a 127,000 acre exploration licence which directly offsets two existing licences acquired in 1995. Ranger's land is situated in the Central MacKenzie Valley immediately south of Norman Wells, Canada's fourth largest onshore oil field. Ranger formed a joint venture in 1997 to drill three exploratory wells. A well spudded at Little Bear at the end of the year has been cased and suspended for further evaluation and testing. A second well at Nota Creek has been suspended. Ranger has a 50 percent interest in all three wells.

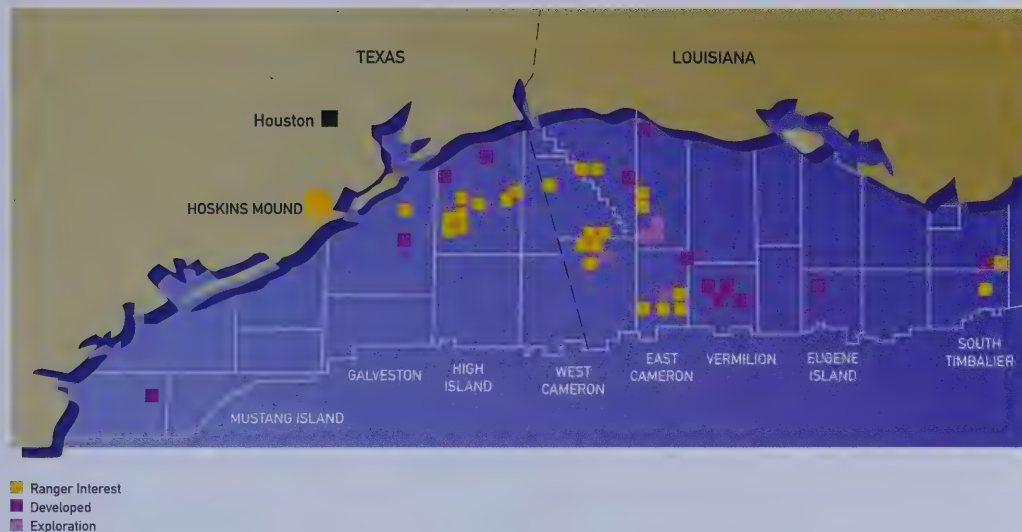
FORT LIARD



FORT NORMAN



US GULF OF MEXICO



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UNITED STATES

Ranger has brought 10 offshore fields onstream in the US Gulf of Mexico since it entered the area in 1993. The Company is focused on exploring in highly gas-prone shallow waters offshore Louisiana and Texas. An office was opened in Houston in 1996 and a large inventory of 2-D and 3-D seismic data acquired.

Gas production in 1997 remained stable as production declines were offset by new production from the South Timbalier 178 gas field which came onstream in December 1996. Oil volumes in 1997 declined slightly as no new oil production was brought onstream.

Ranger participated in a successful exploratory well on South Timbalier Block 179 in which the Company has a 12.5 percent interest. A platform has been set and first production is anticipated in April 1998. An unsuccessful exploration well was drilled in first quarter 1997 on West Cameron Block 490.

In the Federal Central Gulf of Mexico lease sale in 1997, the Company was awarded 11 new offshore licences bringing its holdings to 41 blocks in the shallow waters of the Gulf of Mexico. In early 1998 exploratory drilling commenced on two of these blocks. Both wells were unsuccessful.

STRATEGIC PLAN

Continue to consolidate and rationalize heavy oil operations.

Enhance full-cycle economics through a focus on reducing operating costs, reservoir management and recovery and production technologies.

Evaluate new exploration and land acquisition opportunities.

Develop long-term markets for heavy oil and build downstream alliances with refiners and consumers.

Ranger now has a major heavy oil resource base following the acquisition in September 1997 of ELAN which added five billion barrels of oil-in-place, and daily production of 21,424 barrels in the fourth quarter of 1997. Over the long term, as conventional oil reserves continue to decline in North America, Ranger is positioned for growing heavy oil production. In the current low oil price environment, the focus is on maintaining a core heavy oil business. When prices rebound, the Company is targeting aggressive exploitation.

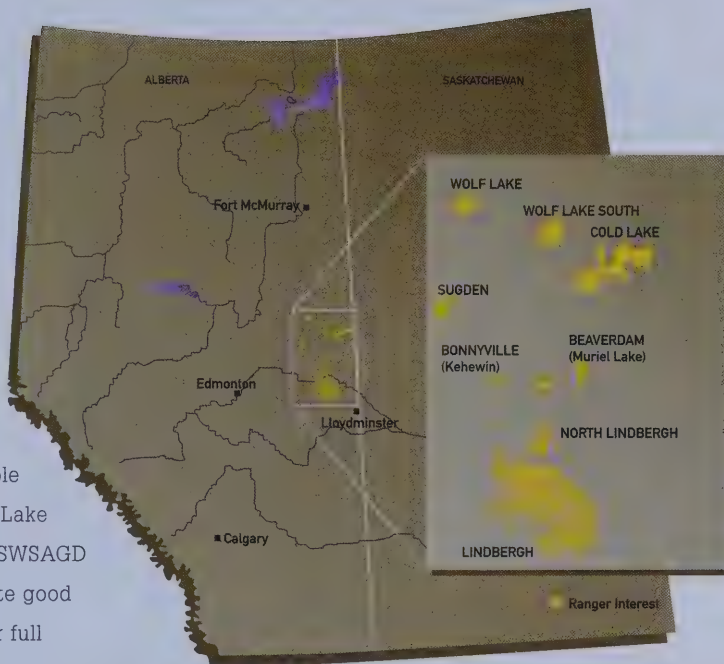
The majority of Ranger's heavy oil production comes from two fields, Lindbergh and Cold Lake. Both fields saw considerable drilling activity in late 1996 and early 1997. Primary production techniques were deployed which utilize screw pumps and aggressive pumping to encourage high rates of sand production during the early life of the wells. This is done in order to stimulate the reservoir and increase oil production rates, and proved successful in both these fields. Expertise in this cold production technology was one of the assets acquired by Ranger and will be a major contributor to future growth.

Lindbergh is the major core asset and since 1995 production has increased more than 50 percent. Current production of 13,400 barrels per day is lower than year end due to some higher operating cost wells being shut-in because of current low oil prices. Successful drilling in North Lindbergh has confirmed the further potential of the area.

The Cold Lake property began production in 1996 and peaked at just over 3,000 barrels per day before low oil prices resulted in the shut-in of some high cost wells and the deferral of drilling and recompletions.

Ranger has a 50 percent interest in the ECHO pipeline which provides a secure source of transportation for Ranger's heavy oil. This innovative heated pipeline transports heavy oil from Lindbergh to Hardisty without condensate diluent. Since starting up in March 1997 the throughput has averaged 27,000 barrels per day.

One of the assets acquired with ELAN is expertise in heavy oil technology. ELAN was the first company in Canada to use single well steam assisted gravity drainage (SWSAGD). This thermal technology has the potential to significantly increase the recovery of heavy oil if applied to suitable reservoirs. A project at Wolf Lake using technology similar to SWSAGD has continued to demonstrate good performance and is ready for full development when prices recover. Ranger believes that technological advances will continue and the full-cycle costs of recovering heavy oil will be further reduced.



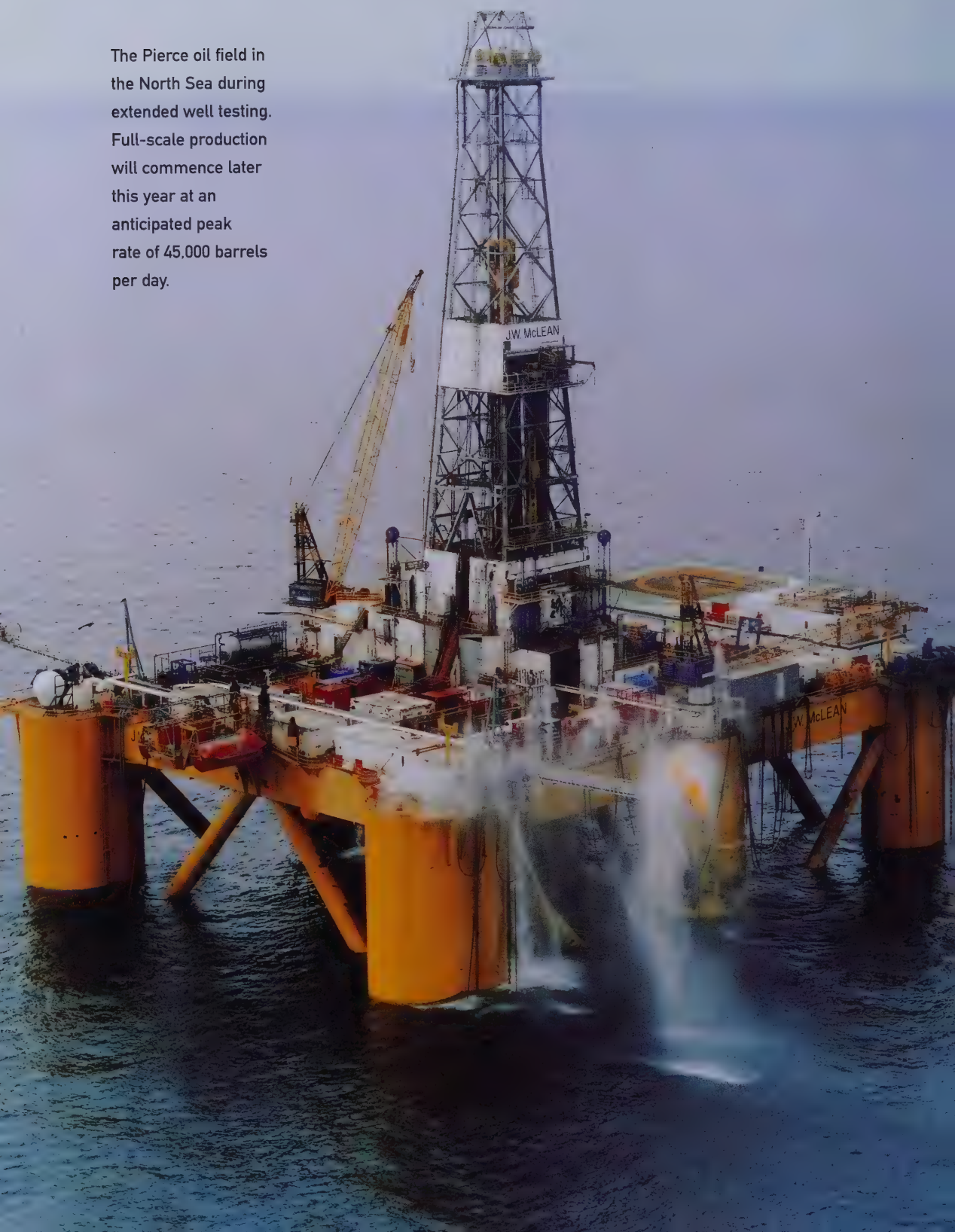
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Improvements in cost efficiency resulted in year-end operating costs under \$5 per barrel. Continued improvements in pumping and producing technologies, as well as sand-handling methods are expected to reduce these costs further in 1998.

PRODUCTION AND RESERVES

Heavy Oil	Interest %	Proven and Probable Reserves (million barrels)	4th Quarter 1997 Production (barrels per day)
Cold Lake	100	50.7	2,767
Lindbergh	75	82.6	16,302
Other	16-100	24.5	2,355
		157.8	21,424

The Pierce oil field in the North Sea during extended well testing. Full-scale production will commence later this year at an anticipated peak rate of 45,000 barrels per day.



North Sea

Strategic Plan

Extract full value from producing fields through enhanced recovery and field optimization.

Complete timely development of existing discoveries.

Build a quality exploration portfolio through licence applications, acquisitions and farm-ins.

Acquire new development and exploitation opportunities.

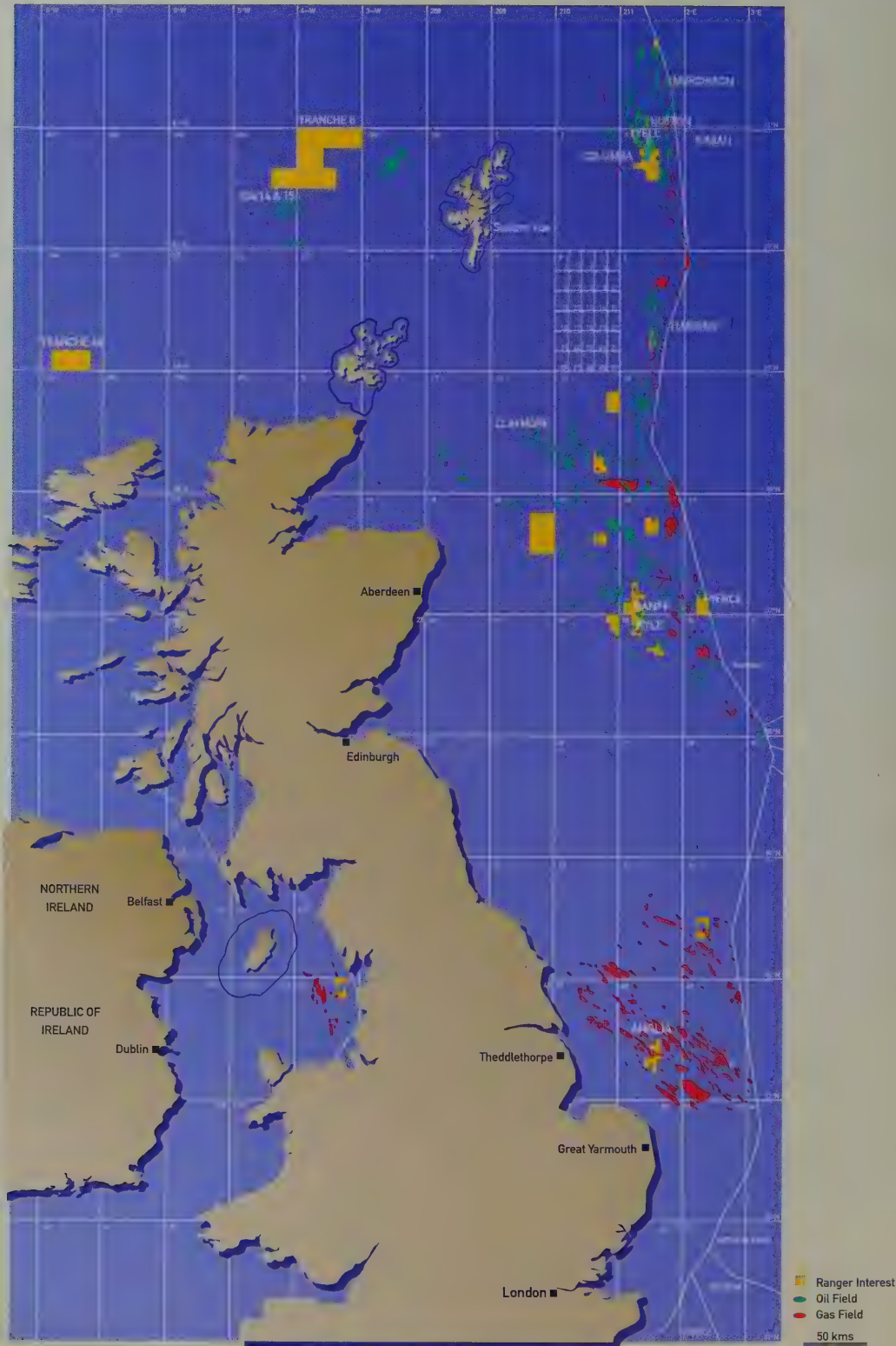
Production & Reserves

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			Average Daily Production		
	Interest %	Proven Reserves (million barrels)	1997	1996 (barrels)	1995
Crude Oil & Natural Gas Liquids					
Ninian	24.1	32.1	11,404	8,411	8,897
Columba 'D'	55.0	8.1	4,168	8,081	4,086
Columba 'B'	21.5	8.6	838	556	—
Columba 'E'	34.1	6.9	—	—	—
Hutton	7.8	1.5	1,104	324	—
Lyell	11.7	1.4	703	177	—
Murchison	9.1	2.7	1,942	456	—
Claymore	4.2	4.1	1,618	1,754	1,816
Harding	5.0	9.5	3,580	1,785	—
Banff	26.2	13.8	1,506	2,024	—
Pierce	15.6	12.9	—	499	—
Kyle	40.0	5.4	—	—	—
Other	—	—	—	—	77
		107.0	26,863	24,067	14,876

			Average Daily Production		
	Interest %	Proven Reserves (billion cubic feet)	1997	1996 (million cubic feet)	1995
Natural Gas					
Anglia	67.2	86.2	19.4	16.2	22.5
Markham	—	—	—	0.1	5.5
Pierce	15.6	31.6	—	—	—
Banff	26.2	9.6	—	—	—
Harding	5.0	10.3	—	—	—
Other	—	6.9	—	—	—
		144.6	19.4	16.3	28.0

NORTH SEA AREAS OF ACTIVITY



NINIAN

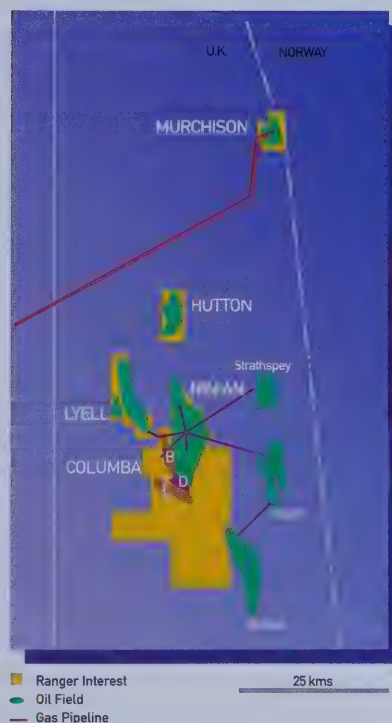
The Ninian field was discovered in 1974 and remains Ranger's largest producing North Sea oil field. In line with the objective of maximizing the value of producing assets, Ranger increased its interest to 24.1 percent from 15.8 percent in October 1996 as part of the Ninian Area acquisition. A prime consideration behind the acquisition was the scope for adding value by increasing reserves and reducing operating costs. An aggressive redevelopment program was initiated in 1997 to achieve these goals. This program is reducing operating costs by cutting overheads and increasing productivity in the work force. It also aims to maximize production and reserves by improved reservoir management including increased development drilling and well work. Two infill wells were drilled in 1997 and up to eight are planned for 1998.

Ninian commenced production in 1979 and to year-end 1997, cumulative production totaled 1,091 million barrels. Year-end reserves totaled 133 million barrels, of which Ranger's share was 32.1 million barrels.

Transportation and Processing Infrastructure

The Ninian and Brent Pipeline Systems are a network of over 450 miles of pipelines that collect and transport production from most of the oil fields in the Northern North Sea – some 25 fields including giants like Brent and Ninian itself, plus Ranger-operated fields Columba 'B' and Columba 'D'. Through the Ninian Area acquisition Ranger increased its interest to 14.9 percent in the Ninian Pipeline System and acquired a 1.8 percent interest in the Brent Pipeline System.

NORTHERN NORTH SEA



The pipelines run southwest to the largest oil terminal in Europe at Sullom Voe in the Shetland Islands. Twenty-seven companies have ownership in Sullom Voe and Ranger has the sixth largest stake at 5.1 percent. The terminal produces stabilized crude oil for onward transportation by tankers. In addition to handling production from Northern North Sea fields, the terminal is well positioned to attract business from the emerging West of Shetlands area where several major discoveries have been made in the last few years.

In 1997 Ranger's share of tariff revenues rose to \$36.5 million, a 39 percent increase over 1996. This reflects additional third party volumes processed at Ninian, along with Ranger's increased interests resulting from the Ninian Area acquisition.

COLUMBA 'B'

Located adjacent to and southwest of Ninian, development of this Ranger-operated field (interest 21.5 percent) has centered on drilling extended-reach wells from the Ninian Southern and Central platforms.

The first of these extended-reach wells was completed in August 1996 to bring production onstream. A second extended-reach water injection well was suspended in 1997 for potential redrilling in 1998. A third extended-reach injection well was completed in January 1998. Current plans are to drill up to five additional wells for a total of four producers and four injectors. Production was shut-in during the first quarter of 1998 while reservoir pressure was rebuilt through injection support. Production is expected to recommence in the second quarter. Columba 'B' oil is transported by pipeline and processed by the Ninian facilities.

COLUMBA 'D'

Since the Ranger-operated Columba 'D' oil field (interest 55 percent) came onstream in 1994, its performance has exceeded expectations. Total production from the field has surpassed 11 million barrels of oil. In line with expected reservoir performance, daily production declined in 1997.

CLAYMORE

Ranger acquired a 4.2 percent interest in Claymore in 1994. Production from this mature oil field has remained relatively stable through a program of infill drilling to offset natural reservoir decline.

HARDING

Ranger has a five percent interest in Harding which commenced production in April 1996. Development to date has focused on the Central and South Harding pools. The field infrastructure includes a three-legged jack-up platform with the capacity to store 500,000 barrels in its gravity base. Oil is exported through offshore loading to a shuttle tanker.

Daily oil production from the field increased to 90,000 barrels by the end of 1997 following drilling of a further seven development wells and de-bottlenecking of the plant processing facilities.

In addition to oil, the field has substantial gas reserves. Associated gas is currently being reinjected into the gas cap, but plans call for the export and sale of gas later in the field's life.

Several options are being investigated to increase the value at Harding. The potential exists for exploitation of satellite pools, as well as generating third party tariff income from selling transportation and processing capacity to nearby fields.

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HUTTON

Ranger acquired a 7.8 percent interest in the Hutton oil field through the Ninian Area acquisition in 1996. Located northwest of Ninian, Hutton is one of Ranger's mature North Sea assets. An active program of reducing operating costs and infill drilling is being pursued.

The field was discovered in 1973 and, following development using a tension leg platform, production commenced in 1984. Oil is exported through the Brent pipeline system to the Sullom Voe Terminal.

LYELL

Ranger acquired an 11.7 percent interest in the Lyell oil field through the Ninian Area acquisition. The field commenced production in 1993 as a subsea satellite of Ninian and production is processed and transported through the Ninian facilities.

MURCHISON

Murchison straddles the UK and Norwegian sectors of the North Sea. Ranger acquired a 9.1 percent interest through the Ninian Area acquisition. Development activities have included a 3-D seismic survey in 1996 over the extent of the field and drilling of four wells in 1997. Oil from Murchison is exported through the Brent pipeline system to the Sullom Voe Terminal.

ANGLIA

The Anglia gas field in the Southern Gas Basin was discovered by a Ranger-operated group in 1972. Development was delayed until 1990 due to low gas prices. Full production commenced in 1991 from an unmanned platform connected to the Lincolnshire Offshore Gas Gathering System. A second development phase to extend the field's plateau production period was initiated in 1992 when two wells were drilled from a subsea template placed in the western sector of the field.

Lower production in 1997 reflected expected reservoir declines and reduced buyer nominations. The average price received during 1997 was \$3.14 per thousand cubic feet.

In 1997 Ranger increased its interest in the field to 67.2 percent. Development activities have focused on improving deliverability. In January 1998 Ranger completed a horizontal sidetrack from an existing well into the central area of the field. The well is currently producing over 20 million cubic feet of gas per day. Future plans include a workover in 1998, and the drilling of laterals and a production well in the southeastern area of the field in 1999.

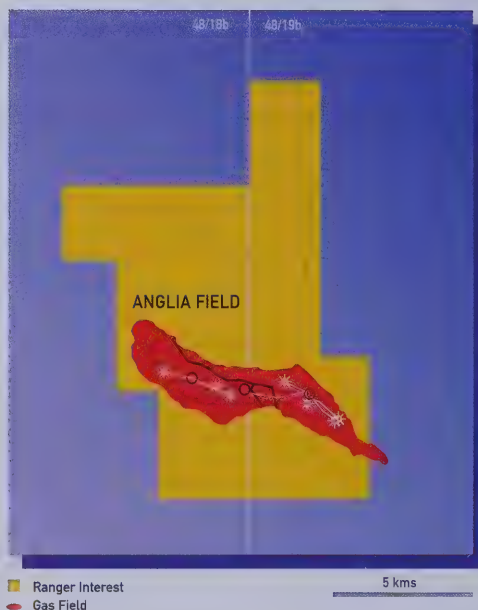
Development

BANFF

The Banff oil field straddles Blocks 29/2a and 22/27a. It was discovered in 1991 and unitized in 1995. Ranger's interest is 26.2 percent.

Phase 1 of field development was completed in February 1997 and included a two-well Early Production System which, over a six-month period, produced at rates up to 40,000 barrels per day. Phase 2 was initiated in 1997 and included drilling two water injection wells. Production from this phase is expected to commence in fourth quarter 1998 and peak at 60,000 barrels of oil per day. Phase 2 oil reserves are estimated at 53 million barrels, 13.8 million barrels net to Ranger. Gas reserves total 37 billion cubic feet of gas, 9.6 billion cubic feet net to Ranger.

ANGLIA



Production facilities have been designed around a new floating production and storage vessel utilizing an innovative hull design. A newly-built tanker will provide supplemental storage and offtake capability during peak production. Oil will be lifted using dedicated shuttle tankers and gas will be exported through a six-inch flowline to a nearby pipeline.

Significant reserve upside exists for Banff. Phase 3 development plans are currently under discussion and include additional drilling in the main chalk reservoir and in other reservoirs around the Banff salt diapir.

PIERCE

The field straddles Blocks 23/27 and 23/22a and was named after Ranger's founder, the late Jack Pierce. In April 1996 unit interests were agreed with Ranger holding 15.6 percent.

Following an extended well test to establish long-term well productivity and reserves, UK government development approval was received in 1997 and full-scale development initiated. Conversion work is currently underway on a floating production, storage and offtake vessel. The field is scheduled to commence full-scale production in fourth quarter 1998 with an anticipated peak rate of 45,000 barrels of oil per day, 7,000 barrels net to Ranger.

While Pierce is currently being developed as an oil field, it also has significant gas reserves. Initially, gas will be re-injected to maintain reservoir pressure, however, plans call for the gas to be produced and sold later in the field's life.

KYLE

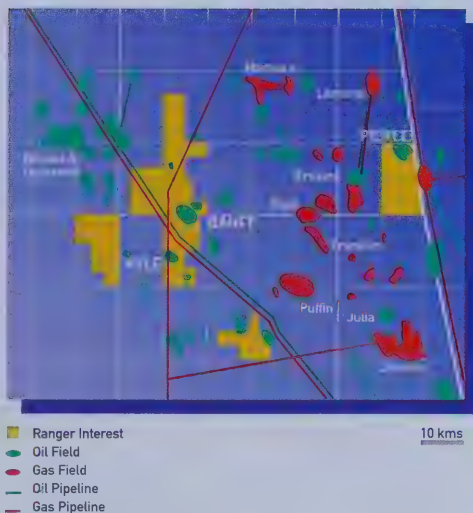
The Kyle oil field is located on Block 29/2c some 12 kilometres southwest of the Banff field. Ranger is the field operator and, in March 1997, doubled its interest in the field to 40 percent.

During 1998 Ranger plans to drill the first horizontal development well. Options being investigated for full-scale development include a subsea tie-back by pipeline to a nearby production facility, possibly at Banff. This would accelerate development with first oil at the end of 1998. Additional production wells will be drilled in 1999.

COLUMBA 'E'

Columba 'E' (interest 34.1 percent) is the third of the Ranger-operated Columba fields adjacent to Ninian and will be initially developed by extended-reach drilling from the Ninian Southern platform. The first development well is currently being drilled and production should commence in mid-1998.

CENTRAL NORTH SEA



Exploration

WEST OF SHETLAND ISLANDS

In 1997 Ranger expanded its land position in an area which has already yielded significant oil discoveries.

Tranche 44

In the 17th Round, Ranger was awarded an 11.7 percent interest in Tranche 44 in the Rockall basin. 3-D seismic has already been acquired across this acreage and drilling is planned for 1999.

Blocks 204/14 and 15

In November, Ranger was awarded a 17.5 percent interest in Blocks 204/14 and 15 which lie immediately to the north of BP's Suilven oil discovery. Suilven is believed to extend onto Ranger's newly acquired blocks. Two wells are planned for 1998 including one to appraise the possible extension of the Suilven discovery.

Tranche 8

Immediately east of Blocks 204/14 and 15 lies Tranche 8 in which Ranger has a 15 percent interest in 10 blocks totalling 500,000 gross acres. Tranche 8 lies to the northeast of the Foinaven and Schiehallion oil fields which each contain an estimated 250-500 million barrels of oil. Extensive 3-D seismic has been acquired over Tranche 8 and a full evaluation of the acreage is currently taking place. The Company is carried through all exploration costs on Tranche 8.

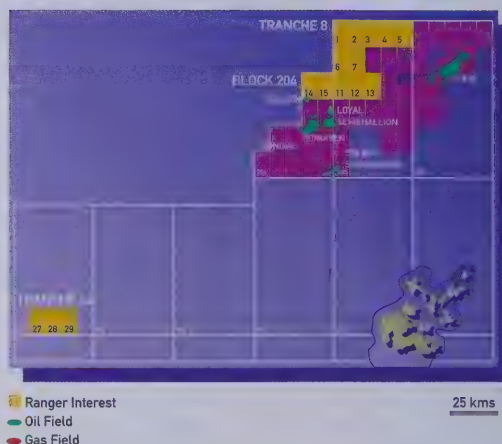
CENTRAL NORTH SEA

In 1997 Ranger continued to expand its activities in the Central North Sea. New interests were acquired in Blocks 20/9, 20/10a, 20/10b, 20/14, 20/15 and 21/14c. Interests were increased in Blocks 22/26b and 29/2c. Two wells were drilled in the area, a Selkirk appraisal well on Block 22/22b, and an exploration well on Block 20/10b. Both wells were unsuccessful.

SOUTHERN GAS BASIN

The Southern Gas Basin which includes the Anglia gas field continues to be a focus of gas exploration. An exploration well spudded in 1997 on Block 44/17a successfully encountered a gas-bearing reservoir. The results of this well are under evaluation and the well has been suspended for potential completion as a development well and tie-back to nearby production facilities. Ranger's interest is 17.5 percent. A further well on a separate exploration prospect is currently drilling.

WEST OF SHETLANDS



Offshore Production Technology

In its 40 years experience in offshore exploration, Ranger has a long history of technological achievements. With the Company's first International production slated from the Kiame field, offshore Angola in the second quarter of 1998, and the Banff and Pierce North Sea fields scheduled to be on production in 1998, Ranger is once again at the forefront of offshore technology.

All three fields will be produced via a floating production, storage and offtake (FPSO) vessel. In comparison to permanent production platforms, an FPSO can dramatically improve full-cycle economics. Development lead times are usually shortened, capital and operating costs can be more easily optimized and abandonment costs are substantially lower than conventional platform development. Furthermore, with all production facilities located onboard the vessel, the FPSO can be readily relocated to another field. Thus, the full amortization of its cost can be spread over more than one field.

When Ninian, Ranger's first North Sea field commenced production in 1979, the leading-edge Central Ninian platform's concrete gravity base was built onshore Scotland and towed to its present site. At the time, it was the largest object ever moved by man. Today, Ranger's FPSO vessels provide an operational efficiency that is greatly enhancing the economics of offshore production.



Newly-built Ramform Banff is having production modules installed before being moved to the Banff Field.



A floating production vessel for the Kiame field with topside being installed.



Berge Hugin is being converted to a floating production vessel for installation on the Pierce field.

A crane installing the topside on a floating production vessel in a Singapore shipyard. The vessel is bound for Ranger's Kiame field, offshore Angola for permanent mooring and hook-up in May.



International

Strategic Plan

- Build an inventory of exploration and exploitation opportunities.
- Drill a portfolio of high impact wells each year on a risk managed basis.
- Focus on North and West Africa and South America.

Production and Exploration

Ranger's first production from its International operations will begin in 1998 when the Kiame oil field, offshore Angola comes onstream. Having established an initial production base and, with excellent exploration prospects in several countries, Ranger's International operations are positioned for rapid growth.

ANGOLA

Kiame

Kiame is located in 465 feet of water on Block 4, a 1.2 million acre block operated by Ranger. The field was discovered in 1993 and three appraisal wells have subsequently been drilled.

Oil production from Kiame (interest 100 percent) is scheduled to commence in the second quarter of 1998 at rates of 7,000 barrels per day, possibly increasing over time depending upon reservoir performance. In preparation for the arrival of a leased FPSO vessel, two existing wells are being recompleted as horizontal multi-lateral development wells. Reserves are estimated to be over eight million barrels of oil.

Block 4

Exploration is continuing on Block 4 with a focus in the west. Ranger's interest in this block is 40 percent. A 1996 exploration well, 4/31-1-3, tested oil at 7,400 barrels per day from Tertiary sands and confirmed the presence of the hydrocarbon fairway seen further west in offsetting deep water blocks. In 1997, the southern extent of this fairway was tested by drilling a well and sidetrack to two adjacent Tertiary prospects. Minor oil shows were encountered and one prospect contained a significant thickness of sand. A further exploration well was drilled at year end, closely offsetting the discovery well at 4/31-1-3. This well confirmed 3-D seismic predictions by encountering excellent reservoir but only oil shows were present.

Several good prospects have been identified through seismic in the west of the block along with numerous leads in the south. The current licence expires in mid-1998 and the Company is reviewing the remaining potential with a view to applying for an extension or renewal.

Block 19

In early 1998, against strong competition, Ranger was awarded a 25 percent non-operating interest in Block 19. This block is located in the deep-water Kwanza basin, some 95 kilometres south of the major oil discoveries on Block 17 at Girassol and Dahlia. Extensive seismic will be acquired and evaluated with plans to drill the first exploratory well in 1999.



CÔTE D'IVOIRE

In 1997 Ranger acquired a significant position in four highly prospective blocks offshore Côte d'Ivoire, all operated by Ranger.

Block CI-26

Ranger acquired a 24 percent interest in Block CI-26 which includes the Espoir field. Although the field was abandoned in 1988, Ranger and its partners believe that advances in drilling and production technology will make it economically feasible to redevelop the field. Prior to abandonment the Espoir field had produced 31 million barrels of oil at rates up to 20,000 barrels per day by natural depletion.

Ranger estimates the field contains potential remaining reserves of about 70 million barrels of oil and 200 billion cubic feet of gas. In addition, the CI-26 block has significant exploration potential. Engineering studies are underway and a decision on redevelopment is expected in 1998.

Blocks CI-101, 102 and 103

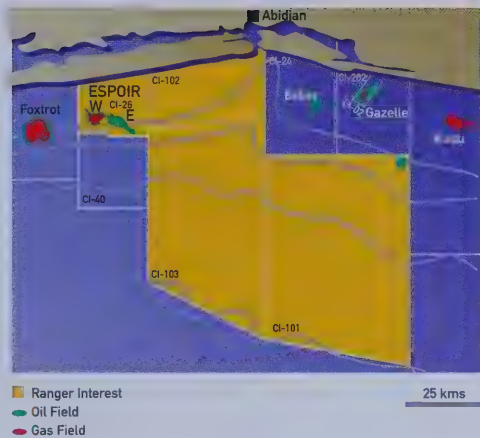
Three other blocks acquired in 1997 have given Ranger a strong presence in the area. In March 1997 Ranger acquired a 24 percent interest in Block CI-102 which lies immediately south of Abidjan and between the Espoir oil field to the west and the Belier oil field to the east. A 1,000 kilometre 2-D seismic program is being acquired on the block.

Later in the year, a Ranger-led consortium was awarded two additional offshore blocks. Block CI-101 and Block CI-103 lie to the south and southeast of CI-102. Ranger holds a 35 percent interest in both. A speculative seismic survey was shot on these blocks during 1997 and the data will be evaluated during 1998.

NAMIBIA

Ranger will have a 70 percent interest, subject to government approval, in Blocks 2713a, 2714a and 2714b which lie immediately to the north of the Kudu gas field. This field is believed to contain several trillion cubic feet of gas. An extensive 3,000 kilometre 2-D seismic survey was acquired across the licence in 1997 and this data is currently being interpreted.

CÔTE D'IVOIRE



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NAMIBIA



ECUADOR

Block 19 (interest 15 percent) is located onshore 120 kilometres southeast of the capital city, Quito, and covers 494,226 acres on the western flank of the prolific oil-producing Oriente basin. Following the acquisition of 400 kilometres of new seismic data, an exploratory well was drilled in 1997 on the Rio Huataracu prospect. The well failed to confirm the presence of commercial quantities of oil and was plugged and abandoned. A second exploratory well is planned for late 1998 or 1999 and will be drilled on the Arapino prospect which has potential reserves of over 100 million barrels of oil.

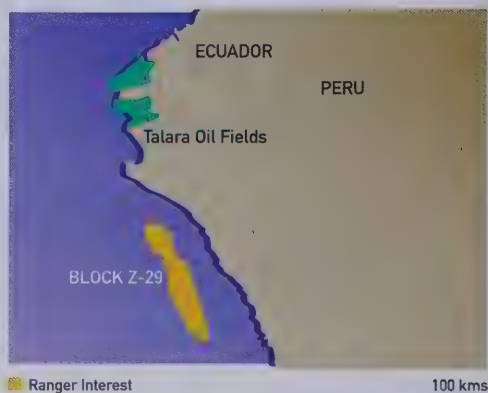
ECUADOR



PERU

In 1997 Ranger acquired a 15 percent interest in Block Z-29 offshore Peru. Several prospects have been mapped on this very large tract and additional infill seismic will be shot in 1998 to identify potential drilling locations. Drilling is planned in 1999.

PERU



ALGERIA

An exploration well was drilled on the Hassi Dzabat permit during 1997. Oil shows were encountered but failed to flow on test. All obligations have been met and the licence has been surrendered.

World-Wide Acreage Holdings

(as at January 1, 1998)

OIL AND GAS DEVELOPED ACREAGE

	Working Interest	Block Numbers	Gross Acres	Net Acres
North Sea Fields				
Ninian	24.1%	3/8a	21,992	5,297
Columba 'D'	55.0	3/8a	903	497
Harding	5.0	9/23b	17,890	896
Murchison	9.1	211/19a, N33/9b	5,160	468
Lyell	11.7	3/2 (Area I)	16,482	1,924
Hutton	7.8	211/27, 211/28a	5,160	400
Banff	26.2	29/2a, 22/27a	5,387	1,412
Columba 'B'	21.5	3/2, 3/7a, 3/8a	4,757	1,021
Anglia	67.2	48/18b, 48/19b	13,089	8,796
Claymore	4.2	14/19	3,500	147
Pierce	15.6	23/27, 23/22a	10,008	1,562
Columba 'E'	34.1	3/7a, 3/7b, 3/8a	11,243	3,829
			115,571	26,249
North America				
Alberta -- conventional			530,484	239,550
-- heavy oil			42,380	37,448
British Columbia			123,028	51,569
Saskatchewan			11,817	8,270
United States			49,653	10,875
			757,362	347,712
			872,933	373,961

OIL AND GAS UNDEVELOPED ACREAGE

North Sea			1,534,505	349,171
North America				
Alberta -- conventional			681,700	436,587
-- heavy oil			129,950	107,785
British Columbia			617,849	290,930
Saskatchewan			474,404	283,559
Northwest Territories			591,433	438,918
United States			143,242	79,817
			2,638,578	1,637,596
Africa				
Angola	40.0%	4 (excluding Kiame)	1,230,081	492,032
Angola	100.0	Kiame	5,332	5,332
Namibia	40.0	2713A, 2714A, 2714B	4,059,130	1,623,652
Côte d'Ivoire	24.0	CI-26	270,575	64,938
	35.0	CI-101	790,226	276,579
	24.0	CI-102	212,753	51,061
	35.0	CI-103	620,715	217,250
South America				
Peru	15.0	Z-29	2,700,000	405,000
Ecuador	15.0	19	494,226	74,134
			10,383,038	3,209,978
			14,556,121	5,196,745

World-Wide Oil and Gas Reserves

CRUDE OIL AND NATURAL GAS LIQUIDS

(before royalties) (million barrels)

	CONVENTIONAL				HEAVY OIL	TOTAL
	North America	North Sea	Angola	Total		
Proven reserves January 1, 1997	10.3	90.3	—	100.6	—	100.6
Purchases	23.8 ⁽¹⁾	0.1	—	23.9	94.6 ⁽¹⁾	118.5
Extensions, revisions and discoveries . . .	5.1	27.0 ⁽²⁾	8.5 ⁽³⁾	40.6	(24.2) ⁽⁴⁾	16.4
Sales	(1.0) ⁽⁵⁾	(0.4)	—	(1.4)	(3.1) ⁽⁵⁾	(4.5)
Production	(2.2)	(9.8)	—	(12.0)	(2.0)	(14.0)
Proven reserves December 31, 1997	36.0	107.2	8.5	151.7	65.3	217.0
Probable reserves December 31, 1997 . . .	9.3	—	—	9.3	92.6	101.9
Proven and probable reserves						
December 31, 1997	45.3	107.2	8.5	161.0	157.9	318.9

Major changes in proven oil reserves were as follows:

(1) The ELAN acquisition.

(2) Mainly at Columba 'B', 'D', 'E' and Kyle.

(3) Approval for the Kiame development.

(4) Proven reserves of heavy oil were reduced at year-end due to the sharp decline in oil prices.

(5) Non-core disposition program.

NATURAL GAS

(before royalties) (billion cubic feet)

	North America	North Sea	TOTAL
Proven reserves January 1, 1997	381.4	91.4	472.8
Purchases	46.7 ⁽¹⁾	40.7 ⁽²⁾	87.4
Extensions, revisions and discoveries	32.8 ⁽³⁾	19.6 ⁽⁴⁾	52.4
Sales	(73.3) ⁽⁵⁾	—	(73.3)
Production	(53.1)	(7.1)	(60.2)
Proven reserves December 31, 1997	334.5	144.6	479.1
Probable reserves December 31, 1997	148.0	—	148.0
Proven and probable reserves December 31, 1997	482.5	144.6	627.1

Major changes in proven gas reserves were as follows:

(1) The ELAN acquisition included proven reserve purchases of 32.9 billion cubic feet of gas.

(2) Additional 29 percent interest in the Anglia field.

(3) Mainly in Canada at Helmet, Edson, Claresholm, Long Coulee, House Mountain and Weyburn.

(4) Mainly at Pierce and Kyle.

(5) Mainly attributable to the Chesapeake alliance in December 1997.

Proven reserves are those quantities of oil and gas which geological and engineering data demonstrate with a reasonable degree of certainty to be recoverable based on year-end economic conditions from known reservoirs using existing technology. Probable reserves are those reserves which are not considered proved at the present time but where geological and engineering data suggest their existence and future recovery.

The above reserves do not include proven and probable oil and gas reserves of 40 million barrels and 60 billion cubic feet respectively, attributable to potential field developments and extensions in the North Sea (Banff Phase 3, Kyle, Columba 'E', Selkirk) and the Côte d'Ivoire (Esport).

Corporate Responsibility

SAFETY, HEALTH AND ENVIRONMENT

Ranger Oil is committed to high standards of safety, health and environmental protection in all its activities. It is the Company's aim to:

- **Provide and maintain for all employees safe and healthy conditions in which to work;**
- **Ensure that the health and safety of third parties and the general public are not jeopardized as a result of its operations; and**
- **Safeguard the environment.**

Attainment of these aims, insofar as it is reasonably practicable, is a top priority for Ranger and in case of conflict, must take precedence over all other corporate goals. In day to day operations this means focusing on a number of key areas:

- **Assuring safety and health of employees;**
- **Protecting the air, water and soil;**
- **Maintaining emergency preparedness;**
- **Minimizing waste;**
- **Restoring and reclaiming sites;**
- **Ensuring energy conservation;**
- **Protecting wildlife and their habitat.**

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Goals and targets for improvement in these key areas are established and continually reviewed. Progress was made in all key areas in 1997.

Accountability for safety, health and the protection of the environment is assigned to line managers. Safety and environmental specialists in the UK and Canada review the operation of Ranger's world-wide interests and report quarterly to a Committee of the Board of Directors. The members of this Committee encourage open dialogue with all Ranger employees to review and act on safety concerns.

COMMUNITY AFFAIRS

Continued financial pressure on governments at all levels to restrain spending impacts community programs. As a result, there is increased demand on companies and individuals to contribute to their communities.

Ranger supports worthwhile community organizations in all its operating areas. In Canada, major beneficiaries in 1997 included: Partners in Health (Calgary Regional Health Authority capital campaign); STARS (Air Ambulance); The Grace Hospital Foundation; Mount Royal College Foundation; Carleton University; The Banff Centre; The University of Saskatchewan's First & Best Program; The University of Regina's Vision 20/20 Program; Performing Arts Stabilization Fund; Calgary Women's

Emergency Shelter; The United Way; The Alberta Lung Association; Alberta Children's Hospital; and William Roper Hull Child & Family Services. In the Northwest Territories, the Company provided computer software upgrades to the Sahtu Divisional Board of Education; jointly developed a monthly community newsletter with the Adult Learning Centre in Tulita, Fort Norman; and made a contribution towards the development of a Traditional Camp. Manpower assistance to liaise with government authorities is provided to communities on an ongoing basis.

In the UK beneficiaries included: The Restoration of Appearance and Function Trust (research for plastic surgery and burn injury treatment); Disability Challenge (a Guildford playcentre for children with physical and learning disabilities); Surrey Crimestoppers (a partnership with Surrey Police to fight crime); Business in the Community (a business consortium formed to improve social, educational and cultural opportunities in Great Yarmouth); and Surrey Young Enterprise (where Ranger provides financial assistance and on-site training by our employees).

In Angola, contributions were made to the children's hospital in Luanda to purchase medical supplies; the Luanda 'Goal Street Kids' project for feeding stations and medical support; educational supplies for Uige Schools; and continued support was given to the community for general medical and educational assistance.

CORPORATE GOVERNANCE

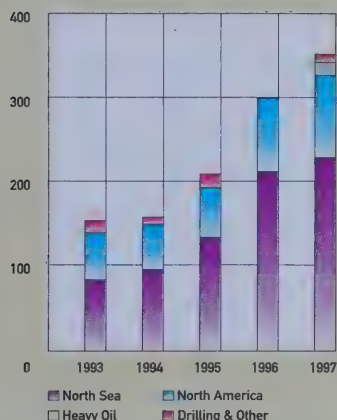
The Toronto Stock Exchange Committee on corporate governance in Canada has issued a series of proposed guidelines for effective corporate governance (TSE Report). As a listing requirement the Toronto Stock Exchange has adopted disclosure by each listed corporation, on an annual basis, of its approach to corporate governance with reference to the TSE Report. Accordingly, particulars of the Company's approach to corporate governance are located in the Proxy Statement and Information Circular.



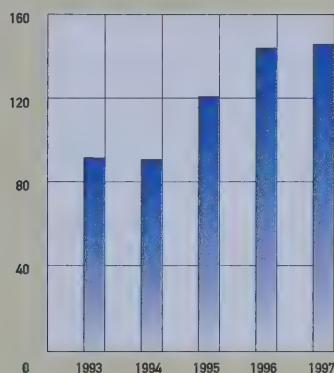
The Luanda 'Goal Street Kids' project provides feeding stations and medical support.

Management's Discussion & Analysis of Results of Operations & Financial Condition

REVENUE
(millions of US dollars)



FUNDS FROM OPERATIONS
(millions of US dollars)



The following discussion and analysis should be read in conjunction with the Consolidated Financial Statements and related notes. All amounts are expressed in United States dollars.

Throughout this report, crude oil and natural gas liquids are referred to as "oil" unless otherwise indicated.

Acquisition of ELAN Energy Inc.

Effective September 29, 1997 Ranger acquired ELAN Energy Inc. (ELAN). The purchase consideration of \$517 million included 26.7 million new Ranger shares and \$276 million of additional debt. Proven and probable reserves acquired amounted to 178 million barrels of heavy oil, 32 million barrels of conventional oil and 36 million cubic feet of gas. Average daily production in the fourth quarter of 1997 from ELAN amounted to 8,855 barrels of light oil, 21,424 barrels of heavy oil and 9 million cubic feet of gas. Primarily as a result of this transaction, shares issued and outstanding increased 27 percent during the year.

Financial Results

Total revenues were \$351 million compared to \$299 million for 1996. Oil prices fell 15 percent averaging \$17.43 per barrel, down from \$20.49 in 1996. This reflected lower world prices as well as the addition of a heavy oil component in the fourth quarter of 1997. Gas prices increased 18 percent, averaging \$1.70 per thousand cubic feet in 1997. Higher prices in North America accounted for the increase.

Operating expenses increased 39 percent to \$124 million in 1997. On a unit-of-production basis (one barrel of oil being equal to ten thousand cubic feet of gas in Canada, eight thousand in the United States and six thousand in the North Sea), costs were \$5.93 per barrel of oil equivalent compared to \$5.14 in 1996. The increase reflected the greater proportion of production coming from high cost producing fields in the northern North Sea and northeastern British Columbia.

Interest charges increased to \$16 million from \$9 million in 1996. Higher average debt levels associated primarily with the ELAN Acquisition accounted for the increase.

Funds generated from operations before tax were \$195 million compared to \$190 million in 1996. Current income tax increased from \$1 million to \$11 million in 1997. The North Sea accounted for most of the increase, with taxable revenues in 1996 being sheltered from income tax by deductions brought forward from previous years. Current North Sea Petroleum Revenue Tax fell to \$38 from \$44 million million as a result of lower oil prices. Funds generated after tax were \$146 million (\$1.38 per share) compared to \$144 million (\$1.46 per share) in 1996.

Depletion and depreciation charges increased to \$131 million compared to \$123 million in 1996. Higher production volumes were responsible for the increase. During 1997 the Company also wrote off \$9 million of unsuccessful exploration costs primarily in Algeria.

Earnings before tax were \$54 million compared to a loss of \$14 million in 1996. The loss in 1996 reflected a \$71 million write-down in Angola. Earnings after tax amounted to \$9 million (\$0.09 per share) compared to a loss of \$56 million (\$0.57 per share) in 1996.

Oil and Gas Operations

Oil and gas revenues for the past three years together with the effect of changes in volumes and prices were as follows:

(millions of US dollars)	1995	Changes Due To		1996	Changes Due To		1997
		Volumes	Prices		Volumes	Prices	
North Sea							
Oil	\$ 92.1	\$ 70.8	\$ 21.6	\$ 184.5	\$ 19.1	\$ (15.5)	\$ 188.1
Gas	31.4	(13.5)	1.1	19.0	3.5	(0.3)	22.2
	123.5	57.3	22.7	203.5	22.6	(15.8)	210.3
North America – Conventional							
Oil	26.8	1.8	6.0	34.6	6.2	(0.3)	40.5
Gas	41.8	17.5	11.7	71.0	(4.7)	14.1	80.4
	68.6	19.3	17.7	105.6	1.5	13.8	120.9
Heavy Oil	–	–	–	–	15.7	–	15.7
Total							
Oil	118.9	72.6	27.6	219.1	41.0	(15.8)	244.3
Gas	73.2	4.0	12.8	90.0	(1.2)	13.8	102.6
	\$ 192.1	\$ 76.6	\$ 40.4	\$ 309.1	\$ 39.8	\$ (2.0)	\$ 346.9

Oil and gas revenues increased 12 percent to \$346.9 million in 1997 from \$309.1 million in 1996, mainly due to increased production in the North Sea, and the ELAN acquisition which added conventional and heavy oil production in Canada in the fourth quarter.

In 1996 oil and gas revenues increased 61 percent to \$309.1 million from \$192.1 million in 1995. North Sea revenues increased by \$80.0 million in 1996 as a result of higher oil production and prices. North American revenues increased by \$37.0 million as a result of higher gas production and prices.

NORTH SEA OIL AND GAS PRODUCTION AND NETBACKS

North Sea daily average production (before royalties) for the past three years was as follows:

	1997	1996	1995
Oil (barrels)	26,863	24,067	14,876
Gas (million cubic feet)	19.5	16.3	28.0

North Sea daily oil production has almost doubled over the past two years as a result of new fields coming onstream and acquisitions. Harding and Columba 'B' came onstream in 1996 and contributed to the increase in 1997 production. Through the Ninian Area acquisition in October 1996, the Company acquired the Hutton, Lyell and Murchison fields as well as additional interests in the Ninian and Columba 'B' fields. The Columba 'D' field showed outstanding performance in 1996, following which production has declined in line with expected reservoir performance.

North Sea daily gas production decreased in 1996 as a result of natural reservoir decline in the Anglia field and the Company's disposal of its remaining interest in the Markham gas field. In 1997 the Company increased its interest in the Anglia field and, following successful completion of a horizontal sidetrack well, was able to increase production to 25 million cubic feet per day in the fourth quarter.

North Sea netbacks on a per unit-of-production basis for the past three years were as follows:

	1997	1996	1995
Oil (per barrel)			
Revenue	\$ 19.09	\$ 21.56	\$ 16.98
Hedging activities	0.10	(0.61)	(0.02)
Royalties	(1.79)	(1.86)	(1.80)
Operating expenses	(7.77)	(6.63)	(7.83)
Netback	\$ 9.63	\$ 12.46	\$ 7.33
Gas (per thousand cubic feet)			
Revenue	\$ 3.14	\$ 3.19	\$ 3.08
Royalties	—	—	—
Operating expenses	(1.22)	(0.92)	(0.75)
Netback	\$ 1.92	\$ 2.27	\$ 2.33

In 1997 the North Sea average oil price was \$2.47 per barrel lower than the previous year. The price for West Texas Intermediate (WTI) crude oil declined \$1.39 to average \$20.61 in 1997. The balance of the reduction in the price received was due to changing quality and Brent/WTI differentials. Ranger's current production receives prices close to and fluctuating with the price of Brent crude oil. Operating costs per barrel over the three years have varied with the proportion of production coming from higher cost fields. New production coming onstream in 1998 will have a lower cost of production and future unit costs are expected to decline during the years of peak production from these new fields.

A portion of North Sea gas production is sold under a long-term contract with the balance currently sold to the spot market. Production is expected to be higher in the winter months to take advantage of more favourable spot market prices.

HEAVY OIL PRODUCTION AND NETBACKS

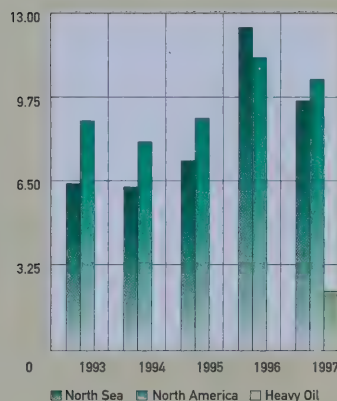
Heavy oil operations commenced with the September 29, 1997 ELAN acquisition. Producing properties are in eastern Alberta, Canada with approximately 80 percent of production from the Lindbergh area. Other producing fields include: Cold Lake, Edgerton, Wolf Lake and Edam. Results for the period since the acquisition were as follows:

	1997
Production, before royalties (barrels per day)	5,400
Netback (per barrel)	
Revenue	\$ 7.87
Royalties	(0.71)
Operating expenses	(4.87)
Netback	\$ 2.29

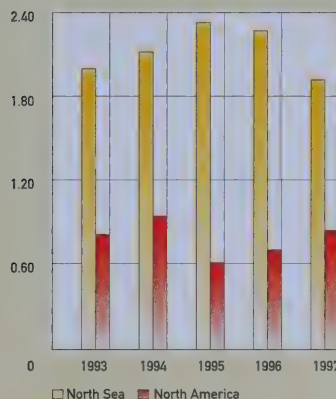
Daily production in the fourth quarter of 1997 averaged 21,424 barrels. Heavy oil is currently trading at a significant discount to the price of light oil, although seasonal factors are expected to provide some improvement in the summer months. Longer term the Company believes that as additional upgrading facilities are constructed, the differential will narrow. Since the acquisition approximately 2,000 barrels of daily production has been shut-in due to declining world oil prices and widening differentials between heavy and light oil. The Company will continue to review heavy oil production levels based on the changing market environment.

Operating expenses on a per barrel-of-production basis are expected to remain higher than for conventional production due to well servicing and fuel costs. Additional costs are incurred separating and disposing of sand produced with the oil, as well as trucking production from the well head to treatment facilities. Unit operating costs are expected to fall as higher cost wells are shut-in.

OIL NETBACK
(US dollars per barrel)



GAS NETBACK
(US dollars per thousand cubic feet)



Ranger acquired ELAN's heavy oil business on the basis of adding long-term value for shareholders. Notwithstanding the recent weakness in commodity prices, the Company remains confident of the long-term future for heavy oil in Canada.

NORTH AMERICAN CONVENTIONAL OIL AND GAS PRODUCTION AND NETBACKS

North American daily average production (before royalties) for the past three years was as follows:

	1997	1996	1995
Oil (barrels)	6,140	5,151	4,948
Gas (million cubic feet)	145.6	154.0	115.8

North American daily gas production decreased five percent in 1997. The impact of the 1996 non-core property disposition program and normal reservoir declines was partially offset by the December 1996 acquisition of additional production in the Helmet area of northeastern British Columbia. In December 1997 the Company sold 40 percent (approximately 16 million cubic feet of daily production) of its interest in the Helmet area for \$50 million. In 1996 North American daily gas production increased 33 percent primarily as a result of the Czar acquisition in November 1995.

North American daily oil production increased 19 percent in 1997. The ELAN properties contributed 2,232 barrels per day to annual production (8,855 barrels per day since the acquisition), offsetting the 1996 non-core property disposition program and normal reservoir declines.

North American netbacks on a per unit-of-production basis for the past three years were as follows:

	1997	1996	1995
Oil (per barrel)			
Revenue	\$ 18.11	\$ 18.96	\$ 15.14
Hedging activities	0.06	(0.61)	(0.31)
Royalties	(4.48)	(4.60)	(3.07)
Operating expenses	(3.23)	(2.46)	(2.80)
Netback	\$ 10.46	\$ 11.29	\$ 8.96
Gas (per thousand cubic feet)			
Revenue	\$ 1.57	\$ 1.35	\$ 0.99
Hedging activities	(0.06)	(0.09)	—
Royalties	(0.28)	(0.21)	(0.15)
Operating expenses	(0.38)	(0.34)	(0.22)
Netback	\$ 0.85	\$ 0.71	\$ 0.62

The North American average oil price in 1997 was \$18.11 per barrel, \$0.85 per barrel lower than in 1996 but \$2.97 per barrel higher than in 1995. Royalty expense over the three years has fluctuated in line with realized oil prices. Operating expenses in 1997 increased as a result of higher cost production from the ELAN properties.

The average North American gas price in 1997 was \$0.22 per thousand cubic feet higher than in 1996 and \$0.58 per thousand cubic feet higher than in 1995. Hedging activities reduced reported gas prices in 1997 to \$1.51 per thousand cubic feet. Unit operating expenses increased in both years as a result of higher cost production from the Helmet area.

DEPLETION AND DEPRECIATION

(millions of US dollars)	1997	1996	1995
North Sea depletion	\$ 52.1	\$ 55.2	\$ 39.1
North American conventional depletion	57.1	55.7	40.7
Heavy oil depletion	9.4	—	—
Tariff asset depreciation	10.5	10.0	7.3
Administrative asset depreciation	1.8	2.3	2.8
Drilling equipment depreciation	—	—	0.5
	\$ 130.9	\$ 123.2	\$ 90.4

The increase in depletion and depreciation expense in 1997 was primarily due to higher production. Depletion expense on oil and gas properties, calculated on the basis of relative energy content (6 to 1), was \$4.93 per barrel in 1997 compared to \$5.26 in 1996 and \$5.00 in 1995. The depletion rate in 1998 is expected to be unchanged in aggregate, with declines as a result of reserve additions in the North Sea being offset by the impact of reduced heavy oil reserves.

In conducting the 1997 ceiling test evaluation, the Company has followed generally accepted accounting standards which provide for a two year exemption from write-down where the purchase price of reserves has been determined on a basis which provides a higher amount than the ceiling test value, and where the excess is not considered to represent a permanent impairment in the ultimate recoverable amount. Due to the impact of a significant price decline on the heavy oil reserves acquired during 1997, capitalized costs with respect to the Canadian cost centre at December 31, 1997 exceeded estimated future net revenues from proved reserves by \$175 million.

INTERNATIONAL ASSET WRITE-DOWNS

(millions of US dollars)	1997	1996	1995
Angola.....	\$ -	\$ 71.1	\$ -
Peru	-	-	8.5
Namibia.....	-	-	4.8
Algeria.....	6.7	-	-
Other	2.1	2.5	1.5
	\$ 8.8	\$ 73.6	\$ 14.8

Under the full cost accounting policy followed by the Company, exploration costs incurred are capitalized on a country-by-country basis. When it is determined that commercial reserves and future prospectivity do not exist within a country to the extent required to justify carrying forward all or a part of the accumulated capitalized costs, part or all of those capitalized costs are written off.

The write-down in 1997 resulted primarily from the drilling of an unsuccessful exploration well in Algeria.

At the end of 1996 the Company reviewed capitalized costs in Angola and determined that, in view of the uncertain prospect of recovering these costs, it would be prudent to write down in full its investment to date in Angola.

FUTURE SITE RESTORATION

(millions of US dollars)	1997	1996	1995
North Sea	\$ 5.7	\$ 5.9	\$ 4.0
North America conventional properties.....	1.7	1.1	1.4
Heavy oil	0.3	-	-
	\$ 7.7	\$ 7.0	\$ 5.4

The increase in future site restoration expense is due to higher production. Future site restoration expense was \$0.32 per barrel in 1997 compared to \$0.33 per barrel and \$0.34 per barrel in 1996 and 1995, respectively. Current estimates for restoration of all the Company's properties total approximately \$130 million of which \$75.9 million is reflected in the accumulated provision in the financial statements at December 31, 1997. The Company does not anticipate incurring significant expenditures on site restoration in the next five years. Effective cash outlays are expected to be reduced significantly through tax relief on these expenditures.

TRANSPORTATION AND PROCESSING

(millions of US dollars)

	1997	1996	1995
North Sea	\$ 36.5	\$ 26.2	\$ 20.3
North America	1.4	1.7	1.9
	\$ 37.9	\$ 27.9	\$ 22.2

North Sea tariff income is generated from utilizing the Ninian pipeline and platform facilities to accommodate crude oil transportation and processing from other nearby fields. The increase in revenues in 1997 resulted from a higher working interest following the Ninian Area acquisition in October 1996. Tariff income is expected to be lower in future years due to production declines in fields currently using the Ninian facilities.

Interest Expense

Interest expense has increased over the past three years as a result of the use of debt to partially finance capital expenditures, including the ELAN acquisition in 1997.

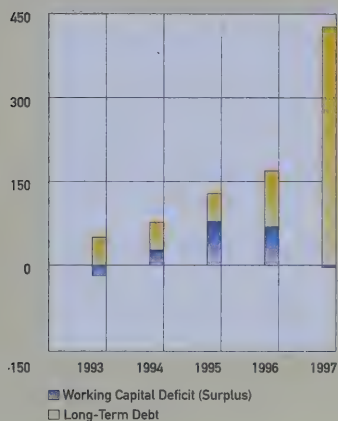
Taxes

The Company accounts for Petroleum Revenue Tax (PRT) by the life-of-field method. The total future liability or recovery of PRT is estimated using current prices and costs and is apportioned to accounting periods on the basis of future estimated revenues. Total PRT expense was \$29.7 million in 1997 compared to \$19.4 million in 1996 and \$1.7 million in 1995. The estimated future PRT liability has increased significantly as a result of reserve extensions, reduced estimates of site restoration costs, the Ninian Area acquisition and, in 1996, higher oil prices.

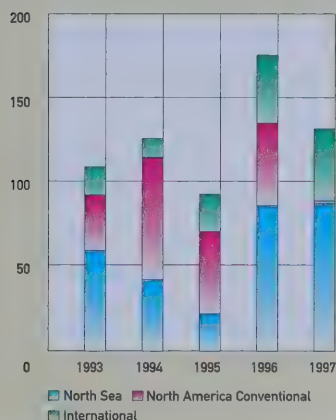
Current PRT expense was \$38.0 million in 1997 compared to \$44.5 million in 1996 and nil in 1995. The reduction in PRT in 1997 was due to lower oil prices. Prior to 1996 the Company was sheltered from PRT by exploration expenditures incurred in previous years.

Income tax expense was \$15.0 million in 1997 compared to \$22.4 million in 1996 and \$8.2 million in 1995. The provision varies with pre-tax earnings in the North Sea, and the UK tax rate which declined two percent to 31 percent effective April 1997.

WORKING CAPITAL & LONG-TERM DEBT
(millions of US dollars)



NET OIL & GAS CAPITAL EXPENDITURES
(millions of US dollars)(excluding corporate acquisitions)



Capital Expenditures

Net capital expenditures over the past three years were as follows:

(millions of US dollars)	1997	1996	1995
Corporate Acquisitions	\$ 517.0	\$ —	\$ 96.7
North Sea			
Exploration	15.9	15.4	10.1
Development	50.4	27.8	28.6
Acquisitions	21.3	46.0	—
Disposals	—	(2.7)	(16.5)
	87.6	86.5	22.2
North America			
Exploration	41.9	34.3	37.2
Development – conventional	27.3	31.9	13.2
– heavy oil	10.1	—	—
Property acquisitions	—	25.3	4.5
Disposals – conventional	(65.9)	(42.7)	(6.8)
– heavy oil	(11.9)	—	—
	1.5	48.8	48.1
International			
Angola – exploration	19.0	35.5	9.9
– development	8.1	—	—
Peru	—	—	8.0
Algeria	2.5	1.4	0.4
Namibia	2.5	—	2.5
Côte d'Ivoire	4.5	—	—
Ecuador	1.4	1.5	—
Other	4.9	2.4	1.5
	42.9	40.8	22.3
Other (net)	(4.2)	3.3	(24.5)
	\$ 644.8	\$ 179.4	\$ 164.8

CORPORATE ACQUISITIONS

In 1997 the Company acquired ELAN Energy Inc. for \$517.0 million. Czar Resources Ltd. was purchased in 1995 for a cash consideration of \$96.7 million. The Czar acquisition added proven and probable reserves in Canada of 203 billion cubic feet of gas and 1.7 million barrels of oil.

NORTH SEA

Two unsuccessful exploration wells were drilled in 1997, one an appraisal of the Selkirk oil discovery and the other a farm-in well on Block 20/10b. In 1996 exploration and appraisal expenditures were incurred on the Pierce field and the drilling of three unsuccessful exploration wells on Block 29/8b, the Anglia Northwest extension and Block 15/24a. In 1995 two unsuccessful exploration wells were drilled.

Significant development activity occurred during 1997 with the Banff and Pierce oil fields moving towards full-scale production in late 1998. Infill drilling progressed at several fields with an important horizontal sidetrack successfully completed in the Anglia gas field. In 1996 development expenditures focused on the Banff and Pierce fields which underwent long-term production tests, together with the Harding and Columba 'D' fields. In 1995 development expenditures were directed primarily towards the Columba 'D' and Harding fields.

Acquisitions in 1997 included an additional 20 percent of Kyle which doubled the Company's interest in this oil field satellite development, and an additional 29.3 percent interest in the Anglia gas field. Expenditures in 1996 related primarily to the Ninian Area acquisition.

The Company disposed of its interest in the Markham gas field in two separate transactions in 1996 and 1995.

NORTH AMERICA

In Canada 25 exploration wells were drilled resulting in 14 gas and 5 oil wells, a 76 percent success ratio. Exploration well P-66 spudded in January 1997 and drilled all year in the Fort Liard area of the Northwest Territories. In the US Gulf of Mexico the Company was successful bidder on 11 offshore blocks in March 1997. Seismic evaluation was carried out and the first exploration well was drilled, unsuccessfully.

In 1996 exploration expenditures of \$34.3 million were incurred adding to the Canadian undeveloped land inventory, drilling 47 wells in Western Canada and drilling 5 wells in the US Gulf of Mexico. In 1995 exploration expenditures were \$37.2 million with the drilling of 40 wells in Western Canada and 6 wells in the US Gulf of Mexico.

Development expenditures in 1997 and 1996 related primarily to winter drilling programs in the Helmet area of northeastern British Columbia, and bringing reserves into production at Elk Point in east central Alberta. In 1995 development expenditures were focused on Sikanni in British Columbia, and Soars and Iron River in northeastern Alberta.

Disposition proceeds in 1997 included \$50 million resulting from the alliance in the Helmet area with Chesapeake Energy Corporation. Other dispositions included non-core heavy oil properties and the Company's ownership interest in the proposed Alliance gas pipeline.

Acquisitions in 1996 were primarily in the Helmet/Midwinter area of northeastern British Columbia. During the second half of 1996 the Company received \$42.4 million from dispositions of non-core properties in Western Canada.

INTERNATIONAL

International expenditures focused on Angola during 1997 and 1996. Following development approval of the Kiame oil field, \$8.1 million of expenditures were incurred in 1997. First production is scheduled for the second quarter of 1998. Three exploration wells were drilled during the year in Angola, one in Ecuador and one in Algeria. All were unsuccessful. In 1995 exploration wells were drilled in Angola, Peru and Namibia.

Capital Resources and Liquidity

The purchase consideration for ELAN included the issue of 26.7 million new Ranger shares with an assigned value of \$233.4 million, and a cash payment of \$151.6 million. Including ELAN's debt acquired on the acquisition, the transaction resulted in \$275.6 million of additional debt. The remainder of the Company's 1997 capital expenditure program was financed by funds generated from operations and proceeds from the disposition of Canadian properties. The 1996 capital program was financed by funds generated from operations, proceeds from the disposition of non-core Canadian properties, and the issue in May 1996 of \$50.0 million of 6.50 percent senior unsecured notes.

Following the ELAN transaction the Company replaced its short-term credit line with a \$425 million facility. Repayments on the \$225 million core portion of this facility commence in November 1998, unless extended by mutual agreement. Repayments under the remaining \$200 million facility are not expected to be required prior to August 1999, providing terms and conditions of the agreement continue to be met. The Company plans to refinance a portion of this facility in 1998 with proceeds from an issue of fixed-rate long-term notes. At December 31, 1996 the Company had a working capital deficiency of \$68.6 million, including short-term bank loans of \$71.4 million.

A cash dividend of \$0.08 per common share (an aggregate of \$7.9 million) was declared by the Board of Directors in 1997 and 1996 with respect to the previous years. In light of falling oil prices the Board of Directors decided not to declare a dividend for the year 1997.

At December 31, 1997 the Company had unused lines of credit amounting to \$102 million. Due to current uncertainty with respect to oil prices, and the significant decline from 1997 levels, the Company is carefully monitoring its 1998 capital program. In March 1998 a reduced capital program of \$235 million was announced. The bulk of this program is directed towards completion of new field development projects in the North Sea and Angola, together with high impact exploration drilling in the North Sea and the Northwest Territories in Canada. The Company believes it will be able to fund its 1998 capital expenditure program with funds generated from operations, non-core property dispositions and available unused lines of credit.

In the longer term, the Company believes that new production from fields coming onstream in 1998 will provide the cash flow to reduce overall debt levels and provide for ongoing exploration programs. A prudent financial position is a key corporate objective and the Company remains committed to maintaining a strong balance sheet.

Risks

The oil and gas business is subject to risks in exploration, development and production activities. These activities can expose Ranger to the risks of destruction of assets, well blowouts, pollution and other operating incidents. The Company maintains liability and physical damage insurance which it considers adequate to cover these risks. In addition, the Company has established safety, emergency and environmental policies and procedures.

Ranger has purchased foreign investment insurance to protect its Angolan assets and activities. This insurance coverage minimizes certain risks of loss to the Company's investment.

The Company's operations depend upon production rates and costs and remaining oil and gas reserves, all of which cannot be estimated accurately. Although the Company expects its exploration and development programs will be successful, there is no assurance that additional commercial oil and gas reserves will be discovered and developed. Under the full cost accounting policy followed by the Company, exploration costs incurred are capitalized on a country-by-country basis. If it is determined that commercial reserves do not exist within a country, those capitalized costs will be written off.

The Company has little or no control over such external factors as oil and gas prices, foreign exchange rates and government regulations. The Company has a hedging policy and has implemented oil and gas hedging activities to help reduce the risk of fluctuating prices. The Company will continue to hedge portions of both its oil and gas production whenever prices and circumstances are considered appropriate. Under this policy up to 50 percent of oil and gas production over the next 12 months may be hedged at any one time.

Year 2000 Compliance

Many existing computer programs and embedded micro processing chips use only two digits to identify a year in the date field. Some of these systems were designed and developed without considering the impact of the upcoming change in the century. If these systems remain non-compliant with the century change, many control systems could fail or create erroneous results by or at the year 2000. The year 2000 compliance issue affects virtually all companies and organizations globally. Companies will have to coordinate their efforts on resolving the year 2000 issue to ensure that suppliers, customers, financial organizations and other business partners with whom they interact are also year 2000 compliant.

The Company has established a task force to ensure that all its control systems continue to function through the year 2000 and beyond. Potential problems could exist with non-compliant control systems and result in, for example, rendering oil and gas field production facilities inoperable. Field and operations audits are being conducted to determine the scope of the problem, the associated costs to correct the problem and to make recommendations that will ensure all of the Company's control systems continue to function through and beyond the transition to the next century.

As part of its due diligence, the Company is inventorying and testing its systems to identify those requiring upgrading or replacement. The Company has set the first quarter 1999 as the target date for which its systems will be year 2000 compliant.

The Company is at this time assessing the total cost to make all its systems year 2000 compliant and does not expect the costs to be material to the financial results of the Company. Costs of achieving compliance will be charged to expense.

Outlook

The Company's strategy in 1998 can be summarized as follows:

In the North Sea, increase oil production from new field developments;

In North America, improve the efficiency of heavy oil operations and develop a base for future expansion when prices improve;

Internationally, bring onstream the Company's first oil field in Angola;

Continue to develop a portfolio of high impact exploration prospects.

Oil production will increase in 1998 as a result of a full year's impact of the ELAN acquisition, commencement of production mid-year from the Kiame field in Angola and Columba 'E' in the North Sea, and production from the Pierce and Banff fields in the fourth quarter. Overall oil production in 1998 is expected to increase over 50 percent. Light oil production in North America should almost double as a result of the ELAN acquisition. Kiame is expected to achieve a rate of approximately 7,000 barrels per day shortly after commencing production. North Sea production should double by year end as a result of

the Banff and Pierce projects which are forecast to add 15,000 and 7,000 barrels per day, respectively, to Ranger's production. In addition, Kyle production is expected to commence by year end. Gas production is expected to decline slightly in North America, mainly as a result of the Chesapeake alliance and the non-core disposition program. In the longer term, the Company expects to increase heavy oil production significantly as prices improve.

The Company currently expects to spend approximately \$235 million on capital programs during 1998 with approximately 70 percent of expenditures dedicated to development. Exploration plans include \$20 million in the North Sea, \$30 million in North America and the balance in International areas. Planned exploration is for five wells in the North Sea, including Blocks 204/14 and 15 West of the Shetlands, up to five wells in the Northwest Territories of Canada, and three wells in the US Gulf of Mexico. Development expenditures include \$100 million for the North Sea and \$30 million for Kiame, with the balance in North America. Major North Sea projects include the Banff, Pierce and Kyle developments, as well as continuing expenditures on the Ninian and Columba fields. Minimal expenditures are forecast for heavy oil while prices remain at current low levels.

Ranger has a diversified production base both geographically and between oil and gas. Oil prices could remain unstable in the short term although, in the longer term, prices are expected to return to levels which provide an acceptable rate of return. A portion of the Company's current North Sea natural gas production is contracted on a long-term basis at fixed prices including automatic escalation in line with inflation and the price of alternative fuels. Ranger estimates that the impact of price changes on funds generated from operations in 1998 is as follows:

(millions of US dollars)	1998
\$1.00 change in oil price	\$ 15
\$0.10 change in gas price	\$ 4

Operating costs are expected to increase in total in 1998 as a result of higher production. On an equivalent barrel of oil production basis, costs are expected to decline overall as a result of new production coming onstream from lower cost fields.

Administrative costs are expected to increase in 1998, commensurate with higher production levels. Interest expense will increase in 1998 because of higher debt levels following the ELAN acquisition.

Current income tax and Petroleum Revenue Tax in the North Sea are sensitive to both capital expenditures and oil prices. Based on forecast production levels, cash taxes payable in 1998 are expected to change approximately \$5 million for each \$1 change in the price of oil.

1997 Financial Section

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Management Report on Responsibility for Financial Statements

The consolidated financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada which, in the case of the Company, conform in all material respects with International Accounting Standards relating to the presentation of historical cost financial information. The financial statements include amounts that are based on management's best estimates and judgments. The financial information presented elsewhere in the Annual Report is consistent with that shown in the consolidated financial statements.

KPMG, independent chartered accountants elected by the shareholders, have conducted an audit of the consolidated financial statements. Their auditors' report, based on an independent examination made in accordance with generally accepted auditing standards, is presented with the consolidated financial statements.

Management is responsible for the integrity of the consolidated financial statements. Systems of internal control have been established and maintained by management to provide reasonable assurance of the protection of assets from unauthorized use or disposition and to produce reliable accounting records for financial reporting purposes.

The Board of Directors has appointed an Audit Committee which consists of four independent directors. The Audit Committee monitors the Company's financial reporting process on behalf of the Board of Directors. In fulfilling its responsibility, the Committee recommended to the Board of Directors, subject to shareholder approval, the appointment of the independent auditors. The Audit Committee discussed with the auditors the overall scope and specific plans for their audit. The Committee met with management and the auditors to review and discuss the annual and quarterly consolidated financial statements.



J. M. D'Aguiar
Vice President, Finance

February 13, 1998



F. J. Dymont
President and Chief Executive Officer

Report of Independent Chartered Accountants

TO THE SHAREHOLDERS OF RANGER OIL LIMITED

We have audited the consolidated balance sheet of Ranger Oil Limited as at December 31, 1997 and 1996 and the consolidated statements of earnings and retained earnings and changes in cash for each of the years in the three year period ended December 31, 1997. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 1997 and 1996 and the results of its operations and the changes in its financial position for each of the years in the three year period ended December 31, 1997 in accordance with generally accepted accounting principles.

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The KPMG logo is displayed in a stylized, handwritten font. The letters are dark blue with a slight shadow effect, giving it a three-dimensional appearance. The 'K' and 'M' are particularly prominent.

KPMG
Chartered Accountants
Calgary, Canada

February 13, 1998

Consolidated Balance Sheet

As at December 31

(millions of US dollars)	1997	1996
ASSETS		
Current Assets		
Cash	\$ 22.4	\$ 14.6
Accounts receivable	109.2	93.0
	131.6	107.6
Property, Plant and Equipment, full cost method (note 3)	1,237.6	729.7
	\$1,369.2	\$ 837.3
LIABILITIES		
Current Liabilities		
Bank loans	\$ -	\$ 71.4
Accounts payable and accrued liabilities	82.7	72.6
Royalties payable	13.7	13.9
Tax payable	16.1	18.3
Current portion of long-term debt	15.1	-
	127.6	176.2
Long-Term Debt (note 4)	427.0	100.0
Deferred Credits	5.3	-
Future Site Restoration	75.9	58.7
Deferred Income and Petroleum Revenue Tax	88.0	93.0
Commitments (note 11)		
SHAREHOLDERS' EQUITY		
Capital Stock (note 6)		
Authorized		
Preferred and common shares without par value		
in unlimited number		
Issued		
Common shares	528.3	293.5
Retained Earnings	117.1	115.9
	645.4	409.4
	\$1,369.2	\$ 837.3

Approved on Behalf of the Board



S. S. Reisman, Director



F. R. Matthews, Director

Consolidated Statement of Earnings and Retained Earnings

Years ended December 31

(millions of US dollars, except per share amounts)

	1997	1996	1995
Revenues			
Oil and gas revenue	\$ 346.9	\$ 309.1	\$ 192.1
Royalties	(43.6)	(36.6)	(21.6)
	303.3	272.5	170.5
Transportation and processing	37.9	27.9	22.2
Other (note 7)	9.8	(1.4)	4.9
Drilling (note 10)	—	—	12.3
	351.0	299.0	209.9
Expenses			
Operating	123.7	89.2	71.0
General and administrative	10.6	10.6	8.7
Interest (note 4)	15.5	9.4	6.9
Depletion and depreciation	130.9	123.2	90.4
International asset write-downs	8.8	73.6	14.8
Gain on sale of drilling rig (note 10)	—	—	(17.1)
Future site restoration	7.7	7.0	5.4
	297.2	313.0	180.1
Earnings (Loss) Before Tax	53.8	(14.0)	29.8
Tax (note 9)			
Current	49.0	45.7	0.8
Deferred	(4.3)	(3.9)	9.1
	44.7	41.8	9.9
Earnings (Loss)	9.1	(55.8)	19.9
Retained Earnings, Beginning of Year	115.9	179.6	167.6
Common Share Dividends (\$0.08 per share)	(7.9)	(7.9)	(7.9)
Retained Earnings, End of Year	\$ 117.1	\$ 115.9	\$ 179.6
Average Number of Shares Outstanding (millions)	106.0	98.7	98.6
Earnings (Loss) Per Common Share	\$ 0.09	\$ (0.57)	\$ 0.20

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Consolidated Statement of Segmented Information

Years ended December 31

(millions of US dollars)	North America					
	Conventional Oil & Gas			Heavy Oil		
	1997	1996	1995	1997	1996	1995
Revenues						
Oil and gas revenue	\$120.9	\$105.6	\$ 68.6	\$ 15.7	\$ —	\$ —
Royalties	(24.7)	(20.3)	(11.8)	(1.4)	—	—
	96.2	85.3	56.8	14.3	—	—
Transportation and processing	1.4	1.7	1.9	—	—	—
Other	1.6	—	—	1.4	—	—
Drilling	—	—	—	—	—	—
	99.2	87.0	58.7	15.7	—	—
Expenses						
Operating	29.2	25.3	16.5	9.7	—	—
General and administrative	4.9	4.3	4.4	0.7	—	—
Interest	—	—	—	—	—	—
Depletion and depreciation	58.0	55.7	40.6	9.4	—	—
International asset write-downs	—	—	—	—	—	—
Gain on sale of drilling rig	—	—	—	—	—	—
Future site restoration	1.7	1.1	1.4	0.3	—	—
	93.8	86.4	62.9	20.1	—	—
Earnings (Loss) Before Tax	5.4	0.6	(4.2)	(4.4)	—	—
Tax						
Petroleum revenue tax — current	—	—	—	—	—	—
— deferred	—	—	—	—	—	—
Income tax — current	1.3	0.9	0.9	0.3	—	—
— deferred	9.0	2.7	1.0	(1.3)	—	—
	10.3	3.6	1.9	(1.0)	—	—
Earnings (Loss)	\$ (4.9)	\$ (3.0)	\$ (6.1)	\$ (3.4)	\$ —	\$ —
Funds Generated from Operations	\$ 63.8	\$ 56.5	\$ 36.9	\$ 5.0	\$ —	\$ —
Segment Assets (net)	\$546.3	\$365.6	\$362.2	\$310.0	\$ —	\$ —

Note: The Company's activities are conducted in three geographic areas: the North Sea, North America and Other International. Other Operations include oil and gas operations in international areas and a drilling rig operation in the United Kingdom prior to its disposition in 1995. Approximately 70% of North Sea production is sold to one customer. The Company believes that alternative customers could be found at similar prices.

North Sea Oil & Gas			Other Operations			Corporate			Total		
1997	1996	1995	1997	1996	1995	1997	1996	1995	1997	1996	1995
\$210.3	\$203.5	\$123.5	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 346.9	\$309.1	\$192.1
(17.5)	(16.3)	(9.8)	-	-	-	-	-	-	(43.6)	(36.6)	(21.6)
192.8	187.2	113.7	-	-	-	-	-	-	303.3	272.5	170.5
36.5	26.2	20.3	-	-	-	-	-	-	37.9	27.9	22.2
1.2	-	-	-	-	-	5.6	(1.4)	4.9	9.8	(1.4)	4.9
-	-	-	-	-	12.3	-	-	-	-	-	12.3
230.5	213.4	134.0	-	-	12.3	5.6	(1.4)	4.9	351.0	299.0	209.9
84.8	63.9	50.3	-	-	4.2	-	-	-	123.7	89.2	71.0
0.6	1.1	0.7	-	-	-	4.4	5.2	3.6	10.6	10.6	8.7
-	-	-	-	-	-	15.5	9.4	6.9	15.5	9.4	6.9
62.7	65.2	46.5	-	-	0.5	0.8	2.3	2.8	130.9	123.2	90.4
-	-	-	8.8	73.6	14.8	-	-	-	8.8	73.6	14.8
-	-	-	-	-	(17.1)	-	-	-	-	-	(17.1)
5.7	5.9	4.0	-	-	-	-	-	-	7.7	7.0	5.4
153.8	136.1	101.5	8.8	73.6	2.4	20.7	16.9	13.3	297.2	313.0	180.1
76.7	77.3	32.5	(8.8)	(73.6)	9.9	(15.1)	(18.3)	(8.4)	53.8	(14.0)	29.8
38.0	44.5	-	-	-	-	-	-	-	38.0	44.5	-
(8.3)	(25.1)	1.7	-	-	-	-	-	-	(8.3)	(25.1)	1.7
9.4	0.3	(0.1)	-	-	-	-	-	-	11.0	1.2	0.8
3.8	21.2	8.4	-	-	-	(7.5)	(2.7)	(2.0)	4.0	21.2	7.4
42.9	40.9	10.0	-	-	-	(7.5)	(2.7)	(2.0)	44.7	41.8	9.9
\$ 33.8	\$ 36.4	\$ 22.5	\$ (8.8)	\$ (73.6)	\$ 9.9	\$ (7.6)	\$ (15.6)	\$ (6.4)	\$ 9.1	\$ (55.8)	\$ 19.9
\$ 97.7	\$103.6	\$ 83.1	\$ -	\$ -	\$ 8.1	\$ (20.6)	\$ (16.0)	\$ (7.1)	\$ 145.9	\$144.1	\$121.0
\$436.1	\$446.2	\$407.8	\$ 41.7	\$ 10.9	\$ 39.7	\$ 35.1	\$ 14.6	\$ 30.7	\$1,369.2	\$837.3	\$840.4

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Consolidated Statement of Changes in Cash

Years ended December 31

(millions of US dollars)	1997	1996	1995
Operating Activities			
Earnings (loss)	\$ 9.1	\$ (55.8)	\$ 19.9
Non-cash items:			
Depletion and depreciation	130.9	123.2	90.5
International asset write-downs	8.8	73.6	14.8
Future site restoration	7.7	7.0	5.4
Deferred tax (reductions)	(4.3)	(3.9)	9.1
Gain on sale of drilling rig (note 10)	—	—	(17.1)
Other, including gains on asset dispositions	(6.3)	—	(1.6)
Funds generated from operations	145.9	144.1	121.0
Changes in non-cash working capital	45.0	(7.2)	3.6
	190.9	136.9	124.6
Financing Activities			
Long-term debt	349.4	50.0	—
Common shares issued	234.7	2.1	0.1
Common share dividends	(7.9)	(7.9)	(7.9)
	576.2	44.2	(7.8)
Investing Activities			
Property, plant and equipment	(188.5)	(153.5)	(113.9)
Corporate acquisitions (note 2)	(517.0)	—	(96.7)
Property acquisitions	(21.3)	(71.3)	(4.5)
Proceeds on sales of property and equipment	77.8	45.4	23.3
Proceeds on sale of drilling rig (note 10)	—	—	25.2
Proceeds on sale of investments (net)	4.2	—	1.8
	(644.8)	(179.4)	(164.8)
Changes in non-cash working capital	(43.1)	6.7	(1.6)
	(687.9)	(172.7)	(166.4)
Increase (Decrease) in Cash	79.2	8.4	(49.6)
Cash, Beginning of Year	(56.8)	(65.2)	(15.6)
Cash, End of Year	\$ 22.4	\$ (56.8)	\$ (65.2)

Cash is net of current bank loans

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Notes to Consolidated Financial Statements

(Tabular amounts in millions of US dollars unless otherwise indicated)

1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada which, in the case of Ranger Oil Limited (the Company), conform in all material respects with International Accounting Standards relating to the presentation of historical cost financial information. Management has made necessary estimates and assumptions in the preparation of these financial statements, primarily relating to unsettled transactions and events as of the date of the financial statements, and actual settlements may differ from the estimated amounts. Significant accounting policies are summarized as follows:

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and all of its subsidiaries.

UNITED STATES (US) DOLLAR REPORTING

The majority of the Company's business is transacted in US dollars and, accordingly, the consolidated financial statements are expressed in that currency.

CURRENCY TRANSLATION

The Company uses the temporal method for translation of its accounts into US dollars under which monetary items are translated at the rate of exchange in effect at the balance sheet date and non-monetary items are translated at rates of exchange in effect when the assets are acquired or obligations incurred. Revenues and expenses are translated at rates in effect at the time of the transactions. Provisions for depletion, depreciation and future site restoration costs are translated at the same rates as the related items. Foreign exchange gains and losses are included in earnings for the period except for unrealized gains or losses related to monetary items with a fixed or ascertainable life extending beyond the end of the following fiscal period. These are deferred and amortized over the remaining life of the related monetary items.

CASH EQUIVALENTS

The Company considers all investments (term deposits, commercial paper, certificates of deposit) purchased with a maturity date of three months or less to be cash equivalents.

INVESTMENTS

Portfolio investments are recorded at the lower of cost or market, and dividends from these investments are included in earnings when received.

OIL AND GAS OPERATIONS

The Company follows the full cost method of accounting for oil and gas operations, as prescribed by the Canadian Institute of Chartered Accountants, whereby all costs of exploring for and developing oil and gas reserves are capitalized and accumulated in country-by-country cost centres. Such costs include land acquisition costs, geological and geophysical costs, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells, interest costs on major development projects and overhead charges directly related to acquisition, exploration and development activities.

The costs related to each cost centre from which there is production, together with the costs of production equipment net of salvage values, are depleted and depreciated on the unit-of-production method based on the estimated proved reserves of each country. Oil and natural gas reserves and production are converted into equivalent units based upon estimated relative energy content. Costs of acquiring and evaluating significant unproved properties are excluded from depletion calculations. These unevaluated properties are assessed periodically to ascertain whether impairment in value has occurred. When proved reserves are assigned or the value of the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion.

The costs (including exploratory dry holes) in cost centres from which there has been no commercial production are not subject to depletion until commercial production commences. The capitalized costs are periodically assessed to determine whether it is likely such costs will be recovered in the future. To the extent there are costs which are unlikely to be recovered in the future, they are written off.

Proceeds from the sale of oil and gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion and depreciation.

Substantially all of the Company's exploration and development activities related to oil and gas operations are conducted jointly with others. The accounts reflect only the Company's proportionate interest in such activities.

CEILING TEST

The capitalized costs less accumulated depletion, depreciation and future site restoration, in each cost centre from which there is production, are limited to an amount equal to the estimated future net revenue from proved reserves plus the cost (net of impairments) of unproved properties. Future net revenue is determined after provision for royalties, direct operating costs, development expenditures, petroleum revenue taxes and the cost of site restoration. Year-end costs and prices are used, except during periods of rapid fluctuations when more representative average prices may be used. Total capitalized costs of all cost centres, less accumulated depletion and depreciation, future site restoration and deferred taxes, are further limited to an amount equal to the estimated future net revenue from proved reserves plus the cost (net of impairments) of unproved properties, less general and administrative expenses, financing costs and taxes.

OTHER ASSETS

Depreciation is provided in the accounts primarily utilizing straight-line methods at annual rates (ranging from 5 percent to 30 percent) which are estimated to amortize the cost of the assets, less salvage values, over their useful lives.

FUTURE SITE RESTORATION

Estimated future removal and site restoration costs are provided for using the unit-of-production method based on the estimated proved reserves of each country. Costs are estimated based on current regulations, costs, technology and industry standards. Removal and site restoration expenditures incurred are charged to the accumulated future site restoration provision account.

PETROLEUM REVENUE TAX

The Company accounts for future UK Petroleum Revenue Tax (PRT) by the life-of-the-field method. The total future liability or recovery of PRT is estimated using current prices and costs. The estimated future PRT is apportioned to accounting periods on the basis of estimated future revenues. Changes in the estimated total future PRT are accounted for prospectively.

INCOME TAX

The Company follows the deferral method of tax allocation accounting under which the provision for income tax is based on the earnings reported in the accounts.

CAPITALIZATION OF INTEREST

Interest incurred on borrowings used to finance major development projects and the construction of other major capital assets is capitalized. Capitalization continues until the project or asset is complete and ready for its intended use.

FINANCIAL INSTRUMENTS

The Company uses certain instruments to manage its exposure to commodity price, foreign exchange and interest rate fluctuations. Instruments are designated as a hedge where there is a close correlation with the timing of an expected future transaction, and the instrument offsets or limits the potential impact of price fluctuations, indirectly establishes the price of the transaction, or changes the nature of a future expense between fixed rates and rates floating with market conditions. Commodity forward and option contracts, foreign exchange contracts and options, and interest rate swaps are used as hedges in managing price and rate fluctuations.

The net amounts paid or received on contracts designated as hedges are recognized in earnings during the same period and as a component of the related transactions. The fair value of these contracts is not reflected in the financial statements. If the hedge of an anticipated future transaction is terminated or a hedge ceases to be effective, the gain or loss at that date is deferred and recognized concurrently with the anticipated transaction. Instruments that are not hedges and hedges that have ceased to be effective are recorded at their fair value and the resulting gain or loss is immediately recognized in earnings.

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2 CORPORATE ACQUISITIONS

Effective September 29, 1997 the Company issued 26,655,819 common shares (with an assigned value of \$233.4 million) and paid cash of \$151.6 million to acquire all the issued and outstanding common shares of ELAN Energy Inc. (ELAN). The acquisition was accounted for by the purchase method. The Company's Consolidated Statements of Earnings and Changes in Cash include operating results of ELAN since the effective date. The purchase price was allocated to net assets acquired based on their estimated fair values.

Property, plant and equipment	\$ 515.6
Non-cash working capital	10.3
Future site restoration	(8.9)
Net assets acquired	<u>\$ 517.0</u>
Issue of common shares	\$ 233.4
Cash paid	151.6
Debt acquired	124.0
Acquisition costs	8.0
Purchase price	<u>\$ 517.0</u>

Management has made a preliminary estimate of the fair value of net assets acquired and allocation of the purchase price may be adjusted in 1998 for material corrections. Acquisition costs include professional fees, employee termination costs and integration costs directly related to the acquisition.

Pro forma operating results (unaudited) for 1997 and 1996, as though the ELAN acquisition had occurred on January 1, 1996, are as follows:

	1997	1996
Revenues	\$ 457.2	\$ 457.9
Earnings (loss)	\$ 2.5	\$ (29.6)
Earnings (loss) per common share	\$ 0.02	\$ (0.24)

Effective November 1995 the Company purchased all of the issued and outstanding common shares of Czar Resources Ltd. (Czar) for consideration of \$79.5 million in cash and the assumption of Czar's debt of \$12.4 million. Costs of the acquisition amounted to \$4.7 million. The acquisition was accounted for using the purchase method and the Company's Consolidated Statements of Earnings and Changes in Cash include operating results of Czar since the purchase date. The acquisition cost of \$96.6 million was allocated to property, plant and equipment (\$93.2 million) and to non-cash working capital (\$3.4 million) based on the fair value of assets acquired.

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3 PROPERTY, PLANT AND EQUIPMENT

As at December 31	Cost	Accumulated Depletion and Depreciation	Net
1997			
Oil and gas			
North Sea	\$ 1,083.5	\$ 672.7	\$ 410.8
North America	1,097.5	314.7	782.8
Other International	108.3	71.1	37.2
Other	19.6	12.8	6.8
	\$ 2,308.9	\$ 1,071.3	\$ 1,237.6
1996			
Oil and gas			
North Sea	\$ 996.1	\$ 610.4	\$ 385.7
North America	578.8	247.1	331.7
Other International	81.8	75.9	5.9
Other	18.0	11.6	6.4
	\$ 1,674.7	\$ 945.0	\$ 729.7

As at December 31, 1997 oil and gas property costs included \$99 million related to properties which were excluded from depletion calculations. These costs were incurred as follows: 1997 – \$80 million; 1996 – \$7 million; 1995 – \$2 million; prior – \$10 million. The Company estimates that a portion of these costs will be included in the costs subject to depletion commencing in 1998 and that all of these costs are expected to be included in the depletion calculation by 2001.

Depletion expense on oil and gas properties, calculated on a barrel of oil equivalent basis (six thousand cubic feet of gas to one barrel of oil) was as follows:

	1997	1996	1995
North Sea	\$ 4.74	\$ 5.63	\$ 5.49
North America	\$ 5.09	\$ 4.94	\$ 4.60
Weighted Average	\$ 4.93	\$ 5.26	\$ 5.00

Excluded from the depletion expense per barrel of oil equivalent were international asset write-downs of \$8.8 million, \$73.6 million and \$14.8 million in 1997, 1996 and 1995, respectively, and depreciation on tariff assets of \$10.5 million, \$10.0 million and \$7.3 million in 1997, 1996 and 1995, respectively.

During the year ended December 31, 1997 the Company capitalized overhead charges directly related to acquisition, exploration and development activities of \$14.9 million (1996 – \$10.5 million; 1995 – \$8.2 million).

In conducting the 1997 ceiling test evaluation, the Company has followed generally accepted accounting standards which provide for a two year exemption from write-down where the purchase price of reserves has been determined on a basis which provides a higher amount than the ceiling test value, and where the excess is not considered to represent a permanent impairment in the ultimate recoverable amount. Using 1997 year-end prices of \$12.37 per barrel for oil and \$1.60 per thousand cubic feet for gas, capitalized costs with respect to the Canadian cost centre exceeded estimated future net revenues from proved reserves by \$175 million. The deficiency was entirely due to a heavy oil price decline at year-end to levels substantially below the longer term price expectations used for evaluating reserves at the time of their acquisition in September 1997 (note 2).

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4 LONG-TERM DEBT AND LINES OF CREDIT

	1997	1996
Bank credit agreement 6.53% ⁽¹⁾	\$ 332.1	\$ –
Limited recourse loan 8.25%	10.0	–
Senior unsecured notes		
6.95% due 2003	50.0	50.0
6.50% due 2008	50.0	50.0
	442.1	100.0
Amount due within one year	15.1	–
	\$ 427.0	\$ 100.0

(1) Floating rate debt. The interest rate reflects the weighted average interest rate on instruments outstanding at December 31, 1997.

The bank credit agreement consists of a \$225 million core facility together with an additional facility for \$200 million. Repayments under the \$200 million facility are not expected to be required prior to August 1, 1999, providing terms and conditions of the agreement continue to be met. Borrowings outstanding at August 31, 1998 under the \$225 million core facility will convert to a term loan, repayable in 16 equal quarterly installments commencing three months after the term date. The term date for the \$225 million facility may be extended by mutual agreement of the Company and its lenders. The facilities are unsecured but are subject to, among other things, certain financial covenants restricting the granting of security for new borrowings and the maintenance of specified financial ratios and net worth tests. At December 31, 1997 borrowings of \$97 million were denominated in Canadian dollars. The Company had standby irrevocable letters of credit totaling \$8 million against these facilities.

The limited recourse loan is repayable in 19 equal semi-annual installments and is secured by certain pipeline assets.

Annual principal repayments of \$10.0 million are required commencing September 30, 1999 on the senior unsecured notes due September 30, 2003, and commencing May 1, 2004 on the senior unsecured notes due May 1, 2008. Both note agreements contain, among other things, certain financial covenants restricting the granting of security for new borrowings and the maintenance of specified financial ratios and net worth tests.

Interest expense incurred on long-term debt in 1997 was \$12.0 million (1996 – \$5.6 million; 1995 – \$3.5 million). Aggregate long-term debt repayments are currently scheduled as follows:

Year	Repayment
1998	\$ 15.1
1999	174.4
2000	67.3
2001	67.3
2002	53.2
Thereafter	64.8
	<u>\$ 442.1</u>

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Unused short and long-term lines of credit at December 31, 1997 amounted to \$102 million.

5 FINANCIAL INSTRUMENTS – RISK MANAGEMENT PROGRAM

The nature of the Company's operations result in exposure to fluctuations in commodity prices, exchange rates and interest rates. The Company monitors and, when appropriate, utilizes derivative financial instruments to manage its exposure to these risks. These instruments are exposed to fluctuations in prices and rates, but by nature of being hedges of an actual transaction or future oil and gas production, any gains or losses will be offset by gains or losses on the hedged transaction. The Company is exposed to credit-related losses in the event of non-performance by counterparties to the financial instruments. The Company deals with only major financial institutions and does not anticipate non-performance by the counterparties.

The Company is exposed to foreign currency fluctuations on its cash flow. The Company periodically uses derivative financial instruments, including forward exchange contracts and currency options, to manage this exposure. At December 31, 1997 the Company had forward exchange contracts maturing throughout 1998 to sell US\$12 million in exchange for Canadian dollars. The rates on these contracts approximated fair market value as at the balance sheet date.

At December 31, 1997 the Company had \$332.1 million of variable rate debt. There were no material contracts or options in place at December 31, 1997 to fix the interest rate on this floating rate debt. At December 31, 1997 and 1996 the fair value of the Company's long-term debt approximated the reported value.

The Company has a commodity price risk management program to increase the certainty of expected cash flows through the use of a combination of derivative financial instruments and fixed and variable price contracts with customers. At December 31, 1997 the Company had sold forward, under price swap agreements, 5.5 billion cubic feet of gas at prices ranging from \$1.31 per thousand cubic feet to \$2.09 per thousand cubic feet.

The estimated fair values of the commodity instruments outstanding at the balance sheet dates, as determined by the estimated cash receipts (payments) necessary to settle the contracts, were:

	1997	1996
Gas price swaps	\$ 1.3	\$ (1.1)
Gas price collars	\$ -	\$ (0.2)
Oil price collars	\$ -	\$ (1.1)

The fair value of other financial instruments, including cash and short-term investments, accounts receivable and accounts payable, approximate their carrying values.

6 CAPITAL STOCK

Changes in outstanding common share capital during the three years ended December 31, 1997 were as follows:

	Number of Shares	Amount
Balance, December 31, 1994	98,590,304	\$ 291.3
Shares issued under employees' stock options:		
- 1995	16,900	0.1
- 1996	363,460	2.1
- 1997	237,660	1.4
Shares issued on acquisition of ELAN (note 2)	26,655,819	233.4
Balance, December 31, 1997	125,864,143	\$528.3

As at December 31, 1997, 5,708,400 common shares of the Company were reserved for employee stock option plans of which options to purchase 5,443,960 shares were outstanding, exercisable at prices ranging from Cdn.\$6.375 to Cdn.\$14.45 per share.

Changes in the number of shares issuable under outstanding options were as follows:

	1997	1996
Shares under option, beginning of year	2,576,720	2,918,100
Options granted	3,404,700	432,100
Options cancelled	(174,300)	(234,620)
Options and stock appreciation rights exercised	(363,160)	(538,860)
Shares under option, end of year	5,443,960	2,576,720

On May 10, 1994 the shareholders of the Company approved a Shareholder Bid Approval Plan (the Plan). Under the Plan, one right was issued for each common share outstanding at the close of business on January 27, 1994 and rights attach to any common shares issued thereafter. The Plan is subject to reconfirmation by shareholders in 1999 and may be terminated by the Board of Directors at any time prior to the rights becoming exercisable.

The rights remain attached to the shares and are not exercisable or separable unless one or more certain specified events occur. If a person or group acting in concert acquires 20 percent or more of the common shares of the Company, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase shares of the Company at a 50 percent discount from the then market price. The rights are not triggered by a Permitted Bid, as defined in the Plan.

7	OTHER REVENUES
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Other revenues were as follows:

	1997	1996	1995
Foreign exchange gains (losses)	\$ 4.4	\$ (3.2)	\$ 1.2
Interest, investment and other income	1.1	1.8	2.1
Gain on sale of property and investments	4.3	—	1.6
	\$ 9.8	\$ (1.4)	\$ 4.9

The Company has operations in the United Kingdom and Canada and, as a result, has non-US dollar denominated debt and working capital. Exchange rate fluctuations result in gains or losses on these non-US dollar denominated items.

8	RETIREMENT BENEFIT PLAN
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The Company maintains a non-contributory pension plan for certain of its employees and contributes to money purchase plans for other employees. Pension fund assets for the non-contributory plan at December 31, 1997 were \$6.1 million. The present value of the accrued pension benefits attributed to services rendered to December 31, 1997 was \$3.9 million. The actuarial liability has been determined using an assumed rate of salary escalation of five percent and a seven percent rate of return on plan assets. In 1997 the pension expense was approximately \$1.1 million (1996 – \$1.0 million; 1995 – \$0.9 million). The Company does not have any other post-retirement benefit plans.

9	TAX
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Tax expense was as follows:

	1997	1996	1995
Earnings (loss) before tax	\$ 53.8	\$ (14.0)	\$ 29.8
Petroleum revenue tax			
Current	38.0	44.5	—
Deferred (reduction)	(8.3)	(25.1)	1.7
	29.7	19.4	1.7
Earnings (loss) before income tax	24.1	(33.4)	28.1
Income tax			
Current	11.0	1.2	0.8
Deferred	4.0	21.2	7.4
	15.0	22.4	8.2
Earnings (loss)	\$ 9.1	\$ (55.8)	\$ 19.9

The deferred income tax provisions result primarily from timing differences between costs claimed for tax purposes and the related depletion and depreciation, asset write-downs and future site restoration expenses.

The actual income tax expense recorded for income tax differs from the amount that would have been expected if the reported earnings had been subject only to the statutory Canadian income tax rate of 44.6 percent. Factors which caused the differences between the expected income tax expense and the actual income tax expense were as follows:

	1997	1996	1995
Expected income tax expense	\$ 10.8	\$ (14.8)	\$ 12.5
Add (deduct) effect of:			
Foreign tax rate differentials	(7.0)	(8.1)	(3.3)
Non-taxable earnings	—	—	(11.0)
Non-deductible royalties less			
related allowances and rebates	0.7	(0.6)	(0.5)
Non-deductible depletion and depreciation	2.8	6.0	3.7
Other non-deductible costs	(2.0)	0.7	0.2
Unutilized losses	8.8	38.3	5.7
Utilization of prior years' losses	(0.9)	—	—
Capital taxes	1.8	0.9	0.9
Actual income tax expense	\$ 15.0	\$ 22.4	\$ 8.2

The Company has estimated tax deductions available to reduce future taxable income in the United Kingdom (\$115 million), Canada (\$490 million) and the United States (\$50 million).

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10	DRILLING RIG
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The Company sold its 50 percent interest in the Sedco 714 semi-submersible drilling rig effective December 31, 1995. The Company's interest in the rig was disposed of for proceeds of \$25.2 million resulting in a gain of \$17.1 million. Revenues and earnings in 1995 from drilling operations up to the date of disposal were \$12.3 million and \$7.7 million, respectively.

11	COMMITMENTS
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At December 31, 1997 the Company had total commitments of \$114 million for non-cancellable operating leases on floating production, storage and offtake vessels to be used in the North Sea and Angola. Minimum payments for the next five years are: 1998 – \$19 million, 1999 – \$41 million, 2000 – \$31 million, 2001 – \$12 million and 2002 – \$6 million.

12	SELECTED QUARTERLY FINANCIAL DATA (unaudited)
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The following summarizes selected quarterly financial data for 1997 and 1996:

(millions of US dollars, except per share amounts and operating statistics)	Quarter				Full Year
	First	Second	Third	Fourth	
1997					
Revenue	\$ 99.2	\$ 68.7	\$ 72.2	\$110.9	\$351.0
Earnings (loss)	\$ 13.1	\$ (2.0)	\$ (5.9)	\$ 3.9	\$ 9.1
Earnings (loss) per common share	\$ 0.13	\$ (0.02)	\$ (0.06)	\$ 0.04	\$ 0.09
Capital expenditures (net)	\$ 39.2	\$ 52.7	\$ 36.7 ⁽¹⁾	\$ (0.8)	\$127.8
Funds generated from operations	\$ 47.0	\$ 27.5	\$ 30.5	\$ 40.9	\$145.9
Daily production					
Crude oil and natural gas liquids (barrels)	38,721	27,232	28,800	58,745	38,403
Natural gas (million cubic feet)	154.9	157.5	161.7	178.6	165.1
Weighted average price					
Crude oil and natural gas liquids (per barrel)	\$20.55	\$18.16	\$18.28	\$14.67	\$17.43
Natural gas (per thousand cubic feet)	\$ 1.97	\$ 1.54	\$ 1.44	\$ 1.85	\$ 1.70

(1) Excludes acquisition of ELAN for \$517.0 million effective September 29, 1997.

1996

Revenue	\$ 61.8	\$ 57.9	\$ 71.1	\$ 108.2	\$ 299.0
Earnings (loss)	\$ 3.7	\$ (2.2)	\$ 3.2	\$ (60.5)	\$ (55.8)
Earnings (loss) per common share	\$ 0.04	\$ (0.02)	\$ 0.03	\$ (0.62)	\$ (0.57)
Capital expenditures (net)	\$ 45.0	\$ 44.0	\$ (10.0)	\$ 100.4	\$ 179.4
Funds generated from operations	\$ 31.5	\$ 27.9	\$ 33.6	\$ 51.1	\$ 144.1
Daily production					
Crude oil and natural gas liquids (barrels)	24,735	23,162	28,318	40,541	29,218
Natural gas (million cubic feet)	167.0	186.2	165.6	162.5	170.3
Weighted average price					
Crude oil and natural gas liquids (per barrel)	\$ 18.12	\$ 18.55	\$ 20.21	\$ 23.24	\$ 20.49
Natural gas (per thousand cubic feet)	\$ 1.51	\$ 1.28	\$ 1.32	\$ 1.70	\$ 1.44

Common Shareholders' and Market Data

MARKET

The common shares of the Company are listed on the Toronto, Montreal, New York and Pacific Stock Exchanges and on The International Stock Exchange of the United Kingdom and the Republic of Ireland.

PRICE RANGE

The following table summarizes the high and low sales prices on the stock exchanges indicated for each quarter of the two fiscal years 1997 and 1996:

	Toronto Stock Exchange (Canadian dollars)		New York Stock Exchange (US dollars)		United Kingdom and the Republic of Ireland (Pounds Sterling)	
	High	Low	High	Low	High	Low
1997						
1st Quarter	\$13.90	\$ 11.20	\$ 10.38	\$ 8.38	£ 6.10	£ 5.20
2nd Quarter	14.95	12.00	10.88	8.63	6.60	5.40
3rd Quarter	14.85	12.25	10.75	8.75	6.70	5.25
4th Quarter	13.70	8.80	9.94	6.06	6.20	4.10
1996						
1st Quarter	\$ 9.88	\$ 7.88	\$ 7.13	\$ 5.88	£ 4.85	£ 3.80
2nd Quarter	10.85	9.25	8.00	6.88	5.20	4.45
3rd Quarter	10.45	9.30	7.75	6.75	4.90	4.40
4th Quarter	13.95	9.85	10.25	7.38	6.00	4.45

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On February 27, 1998 the closing price for common shares reported on the Toronto Stock Exchange was Cdn.\$9.15, on the New York Stock Exchange US\$6.44 and on the International Stock Exchange of the United Kingdom and the Republic of Ireland £4.15.

APPROXIMATE NUMBER OF EQUITY SECURITY HOLDERS

The approximate number of record holders of the Company's common shares at December 31, 1997 was 6,067.

DIVIDENDS

A cash dividend of US\$0.08 per common share was paid in 1997, 1996 and 1995. The Company is a Canadian corporation, and non-residents of Canada are subject to a Canadian dividend withholding tax (currently 15 percent for residents of most other countries).

Ten-Year Statistical Review

(millions of US dollars, except per share amounts)

	1997	1996	1995
FINANCIAL			
Revenue	\$ 351.0	\$ 299.0	\$ 209.9
Funds generated from operations	\$ 145.9	\$ 144.1	\$ 121.0
Funds generated from operations per common share	\$ 1.38	\$ 1.46	\$ 1.23
Earnings before extraordinary items	\$ 9.1	\$ (55.8)	\$ 19.9
Earnings before extraordinary items per common share	\$ 0.09	\$ (0.57)	\$ 0.20
Earnings (loss)	\$ 9.1	\$ (55.8)	\$ 19.9
Earnings (loss) per common share	\$ 0.09	\$ (0.57)	\$ 0.20
Working capital (deficiency)	\$ 4.0	\$ (68.6)	\$ (78.0)
Property, plant and equipment – net	\$ 1,237.6	\$ 729.7	\$ 747.1
Total assets	\$ 1,369.2	\$ 837.3	\$ 840.4
Long-term debt	\$ 427.0	\$ 100.0	\$ 50.0
Common shareholders' equity	\$ 645.4	\$ 409.4	\$ 471.0
Average number of common shares outstanding (millions)	106.0	98.7	98.6
Cash dividends per common share	\$ 0.08	\$ 0.08	\$ 0.08
Market price for shares			
Toronto (\$Cdn.) – High	\$ 14.95	\$ 13.95	\$ 10.13
– Low	\$ 8.80	\$ 7.88	\$ 6.88
New York – High	\$ 10.88	\$ 10.25	\$ 7.50
– Low	\$ 6.06	\$ 5.88	\$ 5.00
TOTAL OIL AND GAS CAPITAL EXPENDITURES			
North Sea	\$ 87.6	\$ 89.2	\$ 38.7
North America	\$ 596.3	\$ 91.5	\$ 151.6
Other International	\$ 42.9	\$ 40.8	\$ 22.3
UNDEVELOPED ACREAGE (thousands of acres)			
North Sea – gross	1,535	1,263	1,205
– net	349	300	303
North America – gross	2,639	1,969	1,834
– net	1,638	1,257	1,005
Other International – gross	10,383	6,880	6,409
– net	3,210	2,467	1,952
CRUDE OIL AND NATURAL GAS LIQUIDS PRODUCTION			
Daily average (thousand barrels) – before royalties			
North Sea	26.9	24.1	14.9
North America	11.5	5.1	4.9
Total	38.4	29.2	19.8
NATURAL GAS PRODUCTION			
Daily average (million cubic feet) – before royalties			
North Sea	19.5	16.3	28.0
North America	145.6	154.0	115.8
Total	165.1	170.3	143.8

1994	1993	1992	1991	1990	1989	1988
\$ 158.6	\$ 154.7	\$ 154.5	\$ 120.7	\$ 160.3	\$ 132.9	\$ 94.7
\$ 91.2	\$ 91.9	\$ 120.0	\$ 80.0	\$ 94.5	\$ 66.9	\$ 50.4
\$ 0.93	\$ 0.93	\$ 1.22	\$ 0.82	\$ 1.07	\$ 0.84	\$ 0.67
\$ 6.1	\$ 20.2	\$ 23.5	\$ 5.8	\$ 42.4	\$ 23.2	\$ 10.2
\$ 0.06	\$ 0.21	\$ 0.24	\$ 0.06	\$ 0.46	\$ 0.27	\$ 0.12
\$ 6.1	\$ 20.2	\$ 23.5	\$ 5.8	\$ 42.4	\$ 51.9	\$ 15.4
\$ 0.06	\$ 0.21	\$ 0.24	\$ 0.06	\$ 0.46	\$ 0.63	\$ 0.19
\$ (26.9)	\$ 18.4	\$ 27.8	\$ 48.7	\$ 150.5	\$ 135.7	\$ 108.9
\$ 675.1	\$ 618.4	\$ 577.6	\$ 490.1	\$ 383.5	\$ 371.8	\$ 308.7
\$ 752.3	\$ 679.6	\$ 641.3	\$ 590.0	\$ 588.8	\$ 564.8	\$ 458.6
\$ 50.0	\$ 50.0	\$ 33.0	\$ 3.1	\$ 6.3	\$ 82.1	\$ 81.6
\$ 458.9	\$ 460.2	\$ 447.8	\$ 432.1	\$ 423.2	\$ 312.4	\$ 202.4
98.6	98.5	98.5	98.5	97.1	84.6	74.6
\$ 0.08	\$ 0.08	\$ 0.08	\$ 0.08	\$ 0.06	\$ —	\$ —
\$ 9.88	\$ 7.88	\$ 9.38	\$ 10.00	\$ 9.63	\$ 7.75	\$ 7.88
\$ 6.38	\$ 5.38	\$ 6.38	\$ 7.00	\$ 6.63	\$ 5.88	\$ 5.38
\$ 7.13	\$ 6.13	\$ 7.75	\$ 8.88	\$ 8.38	\$ 6.50	\$ 6.38
\$ 4.88	\$ 4.25	\$ 5.00	\$ 6.00	\$ 5.63	\$ 5.00	\$ 4.00
\$ 85.1	\$ 59.8	\$ 101.0	\$ 133.3	\$ 54.8	\$ 34.1	\$ 84.0
\$ 76.2	\$ 41.5	\$ 73.7	\$ 19.0	\$ 29.0	\$ 62.1	\$ 9.1
\$ 12.1	\$ 17.9	\$ 4.3	\$ 2.2	\$ 1.6	\$ 10.4	\$ 1.2
1,354	1,638	2,209	2,707	2,656	2,932	2,958
356	378	463	605	520	464	498
999	880	1,059	788	761	640	476
568	444	517	364	354	303	257
4,196	4,196	4,602	1,713	554	554	1,484
1,278	1,940	2,279	929	64	101	—
10.7	9.0	10.2	10.1	14.1	16.0	13.5
4.4	4.8	3.7	2.7	2.7	1.8	1.1
15.1	13.8	13.9	12.8	16.8	17.8	14.6
25.9	29.9	22.4	1.7	—	—	—
80.3	83.0	71.7	56.6	46.1	33.1	26.1
106.2	112.9	94.1	58.3	46.1	33.1	26.1

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RANGER OIL LIMITED Board of Directors

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an investment holding company

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Calgary, Alberta
Retired Oil Executive

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International Petroleum Consultant

Frederick J. Dymment, C.A.
Calgary, Alberta
President and Chief Executive Officer

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Sceptre, Saskatchewan
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Chief Operating Officer

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Counsel for the Company

Lord Moynihan
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Partner of CMA Associates,
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Power Corporation of Canada,
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President of Trade & Investment Advisory
Group Inc., a private consulting company

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Senior Vice President,
Business Development

Kellam Colquitt
Vice President, International Exploration;
Western Hemisphere

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Vice President

John G. Faulds, B.A.
Vice President, Risk Management/
Vice President, Investor Relations

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LL.B., P.Adm.
Vice President, Legal and Corporate
Affairs/Secretary

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William L. Hodgson
Vice President, Operations –
Heavy Oil Division

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Senior Vice President, Canadian Operations

Michael A. Langley, P.Eng.
Senior Vice President, Heavy Oil Division

Ian McIntosh, B.Sc., P.Eng.
Vice President, Canadian Production

Bruce E. McGrath
Assistant Secretary

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Vice President

Thomas C. Sandeman, B.Comm., C.A.
Treasurer

Norman Thachuk
Vice President, Canadian Exploration

RANGER OIL (U.K.) LIMITED Senior Personnel

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Chairman

Martin Cole
Director, Exploitation

Philip A. Dimmock, M.A.
Managing Director

Alan J. Dingley, B.Sc., P.Eng.
Director, Commercial

Steven P. O'Reardon, B.Sc.
Director, Human Resources

Malcolm H. Pattinson, B.Sc.
Director, Exploration

William W. Stiles, B.Sc., A.C.A.
Director, Finance

WEST AFRICA Senior Personnel

Kenneth P. Seymour, B.Sc., Ph.D.
M.B.A., C.Eng.
General Manager, Angola

RANGER OIL COMPANY Senior Personnel

Kellam Colquitt
Vice President

Marvin R. Rathke
Vice President

Bankers
Bank of Montreal
Calgary, Alberta

Auditors
KPMG
Calgary, Alberta

Legal Counsel
MacKimmie Matthews
Calgary, Alberta

Norton Rose
London, England

Head Office – Canada
1600, 321 – 6th Avenue S.W.
Calgary, Alberta, Canada T2P 3H3
Telephone: (1) 403-232-5200
Fax: (1) 403-263-0090
Website: <http://www.ranger-oil.com>

Heavy Oil Division – Canada
3900, 150 – 6th Avenue S.W.
Calgary, Alberta, Canada T2P 3Y7
Telephone: (1) 403-266-8500
Fax: (1) 403-262-7337

United Kingdom
Ranger Oil (U.K.) Limited
Ranger House, Walnut Tree Close
Guildford, Surrey GU1 4US, England
Telephone: (44) 1483-401-401
Fax: (44) 1483-401-414

United States
Ranger Oil Company
910 Travis, Suite 2160
Houston, Texas 77002, USA
Telephone: (1) 713-654-2111
Fax: (1) 713-654-2117

Angola
Ranger Oil Limited
Rua dos Enganos 1-1, CP 5876
Luanda, Republic of Angola
Telephone: (244) 2-396145/
(871) 3863 10046
Fax: (244) 2-395445

Namibia
Ranger Oil Limited
10 Lessing Street
Windhoek, Namibia
Telephone: (264) 61-234161
Fax: (264) 61-239027

Côte d'Ivoire
Ranger Oil Côte d'Ivoire S.A.R.L.
Angle Av. Houdaille Rue de Tessière
Immeuble Ranger Oil Abidjan-Plateau
01 B.P. 8707, Abidjan 01, Côte d'Ivoire
Telephone: (225) 32 26 51
Fax: (225) 32 26 49

Committees

AUDIT COMMITTEE

The Audit Committee reviews the Company's financial statements and recommends approval to the Board of Directors. Audit plans and procedures are reviewed and established, and recommendations are made to the Board concerning internal control procedures and management information systems. Members of this Committee are Messrs. F. Richard Matthews (Committee Chairman), William A. Gatenby, John A. Rae and S. Simon Reisman.

NOMINATING AND CORPORATE GOVERNANCE COMMITTEE

The Nominating and Corporate Governance Committee recommends suitable candidates for director positions to the Board of Directors. In addition, the Committee assists the Board on corporate governance issues and compiles results of the directors' questionnaire dealing with the effectiveness of the Board, its members and Committees. Members of this Committee are Messrs. William A. Gatenby (Committee Chairman), Edward M. Bronfman, Robert W. Campbell and S. Simon Reisman.

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COMPENSATION COMMITTEE

The Compensation Committee administers the executive compensation program. The Committee recommends to the Board the salary of the President and Chief Executive Officer, sets compensation for the Chairman of the Board and approves salaries of senior officers, as well as stock options to executive officers and other key employees. The Committee also reviews the design and general competitiveness of the Company's compensation and benefits program. Members of this Committee are Messrs. Robert W. Campbell (Committee Chairman), Charles M. Carr, Jr., F. Richard Matthews and John A. Rae.

SAFETY, HEALTH AND ENVIRONMENTAL COMMITTEE

The Safety, Health and Environmental Committee ensures effective programs are in place relating to safety, health and environmental matters, including identification of risk and compliance with legal requirements. The Committee ensures management administers the Company's policies on these matters. Members of this Committee are Messrs. Charles M. Carr, Jr. (Committee Chairman), Edward M. Bronfman, Robert W. Campbell, William A. Gatenby and Lord Moynihan.

Shareholder & Investor Relations Information

INVESTOR RELATIONS INQUIRIES MAY BE DIRECTED TO:

John G. Faulds
Vice President, Investor Relations
at the Company's Head Office in Canada
Telephone: (1) 403-232-5203
E-Mail: InRel@calgary.ranger-oil.com
Website: <http://www.ranger-oil.com>

SHAREHOLDER INQUIRIES MAY BE DIRECTED TO:

CIBC Mellon Trust Company
Calgary, Alberta, Canada
Telephone: (1) 800-387-0825 (Toll free in Canada and the United States)
or (1) 403-232-2400
E-Mail: inquiries@cibcmellon.ca

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TRANSFER AGENTS & REGISTRARS

CIBC Mellon Trust Company
Calgary, Vancouver, Toronto, Montreal, Canada; London, England
ChaseMellon Shareholder Services
New York, USA

STOCK EXCHANGE LISTINGS

Toronto Stock Exchange (RGO)
Montreal Stock Exchange (RGO)
New York Stock Exchange (RGO)
Pacific Exchange (RGO)
The International Stock Exchange, London (RGR)



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